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IPP

INTERMOUNTAIN POWER PROJECT
A DEVELOPMENT OF INTERMOUNTAIN POWER AGENCY

July 15, 1983

Mr. Brent C. Bradford
Executive Secretary
Utah Air Conservation Committee
150 West North Temple
Salt Lake City, Utah 84110

Dear Mr. Bradford:

Intermountain Power Project (IPP)
Revised Request for Information

This is to supplement our letter to you dated June 22, 1983 which was in response to your letter of June 8, 1983 requesting additional information pertaining to issuance of a modified air quality approval order for the IPP.

The enclosed "Position Paper on Utah Review of IPP Permit" and its attachments reiterate our legal position, summarizes the factual basis for concluding that the emission limits in the original air quality approval order still represent best available control technology, explains how the proposed control equipment will assure compliance with those emission limits and responds to certain concerns that have been expressed by interested individuals.

If you or your staff require any additional information, please contact Mr. Roger T. Pelote at (213) 481-3412.

Sincerely,

James H. Anthony, RP

JAMES H. ANTHONY
Project Director
Intermountain Power Project

Enclosure

cc: Mr. D. Kircher w/Enclosure
EPA Region VIII
1860 Lincoln Street
Denver, Colorado 80295

Mr. Roger T. Pelote w/Enclosure

bcc: Mr. Henry V. Nickel w/Enclosure
Hunton & Williams
1919 Pennsylvania Avenue, N.W.
Washington, D.C. 20036

Mr. James A. Holtkamp w/Enclosure
Van Cott, Bagley, Cornwall & McCarthy
Suite 1600
50 South Main Street
Salt Lake City, Utah 94144

Mr. Lowell L. Smith w/Enclosure
Manager, Western Engineering Division
KVB
P.O. Box 19518
Irvine, California 92714

Mr. Donald O. Swenson w/Enclosure
Project Air Pollution Control Systems Engineer
Black and Veatch Consulting Engineers
P.O. Box 8405
Kansas City, Missouri 64114

Mr. Ronald L. Rencher w/Enclosure
Acting General Manager
Intermountain Power Agency
The Atrium, Suite 101
5250 South 300 West
Murray, Utah 84107

Ms. Ann Garnett w/Enclosure
Public Affairs Manager
Intermountain Power Agency
The Atrium, Suite 101
5250 South 300 West
Murray, Utah 84107

D. W. Waters
D. Hyska
J. H. Anthony w/Enc.
V. L. Pruett
R. L. Nelson w/Enc.
B. Campbell w/Enc.
IPP File w/Enc.
Robert C. Burt
Patrick P. Wong
A. S. Buchanan
E. N. Friesen

S. R. Seid
J. J. Carnevale w/Enc.
N. F. Bassin w/Enc.
R. E. Gentner w/Enc.
D. W. Fowler w/Enc.
D. J. Waters
T. L. Conkin w/Enc.
Luis E. Escalante
Sr. Engr. of APERA w/Enc.
L. A. Kerrigan w/Enc.

Intermountain Power Project

Position Paper

on the

Utah Department of Health's

Review of the IPP Construction Permit

July 18, 1983

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Attachment 2	ERT report entitled "Effects of NOx Emissions from the Proposed Inter- mountain Power Project on Deposition and Surface Water Acidifica- tion in the Wasatch and Uinta Mountains."
Attachment 3	H. E Cramer's July 1, 1983 letter to James Anthony, responding to comments by the Utah Chapter of the Sierra Club on IPP's NOx emissions.
Attachment 4	The April 1980 study by the Los Angeles Department of Water and Power entitled "Study for Particulate Control Equipment--Electrostatic Precipitators and Fabric Filters--Intermountain Power Project.
Attachment 5	The Department of Water and Power study entitled "The Specification & Design of High Availability Boilers for the Intermountain Power Project".
Attachment 6	A survey by the Utility Data Institute (UDI) concerning NOx emission limits imposed on other bituminous coal-fired power plants.
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IPP POSITION PAPER

I. Introduction

On December 3, 1980, the Utah Department of Health (DOH) issued the Intermountain Power Project (IPP) an approval order to build the four-unit, 3000 MW Intermountain Generating Station (IGS). That order included emission limits reflecting the degree of emission reduction attainable by "best available control technology" (BACT). These BACT limits were specified for sulfur dioxide (SO2), nitrogen oxides (NOx), and particulate emissions and were based upon the determination of the emission levels that could be attained by control technology which was available in 1980. IPP proceeded to make design, procurement and substantial financial commitments to meet the design objectives established by the 1980 BACT emission limits.

On June 8, 1983 -- shortly after IPP announced that IGS would be reduced from four units to two units -- the DOH requested additional information on the feasibility and costs of retrofitting alternative methods for controlling SO2 and NOx emissions at IPP's IGS. The information was requested to aid DOH in its decision to re-evaluate its 1980 BACT determinations. On July 6, 1983, IPP representatives met with DOH staff. At that meeting, possible changes in the BACT emission limits for SO2 and NOx were identifed by DOH staff.

The purpose of this memorandum is twofold. First, it reiterates IPP's legal position opposing BACT re-review for IGS. Second, it summarizes the legal, policy, and technical reasons why the current emission limits in the IPP permit represent BACT for IGS, and explains why the proposed control equipment will assure compliance with the current permit limitations.

This memorandum is supported by extensive technical analyses. In June, IPP submitted to DOH KVB's June 1983 report, entitled "Technical Evaluation of Alternative NOx Control Technologies" ("the KVB Report"), and Black & Veatch's June 1983 report entitled "Cost Analysis of Various NOx and SO2 Control Technologies for the Intermountain Power Project" (the "Black & Veatch Report"). Attached to this Position Paper are additional technical analyses and other relevant information. Attachment 1 is a supplemental KVB report entitled "Review and Evaluation of Mill Creek Unit 3 and A.B. Brown Unit 1 NOx Data" ("the Supplemental KVB Report"). Attachment 2 is an ERT report entitled "Effects of NOx Emissions from the Proposed Intermountain Power Project on Deposition and Surface Water Acidification in the Wasatch and Uinta Mountains." H. E Cramer's July 1, 1983 letter to James Anthony, responding to comments by the Utah Chapter of the Sierra Club on IPP's NOx emissions, is Attachment 3. Attachment 4 is the April 1980 study by the Los Angeles

Department of Water and Power entitled "Study for Particulate Control Equipment--Electrostatic Precipitators and Fabric Filters--Intermountain Power Project." The Department of Water and Power study entitled "The Specification & Design of High Availability Boilers for the Intermountain Power Project" is Attachment 5. Attachment 6 is a survey by the Utility Data Institute (UDI) concerning NOx emission limits imposed on other bituminous coal-fired power plants. Attachment 7 is a July 1, 1983 memorandum from Black & Veatch concerning SO2 removal costs per ton of SO2 removed. Finally, Attachment 8 is a 1978 memorandum from EPA entitled "BACT Information for Coal-fired Power Plants."

II. IPP'S Position Concerning DOH's Current BACT Inquiry

IPP believes that it is inconsistent with the law and otherwise inappropriate for DOH to re-review the BACT limits for the IPP's Intermountain Generating Station. An administrative agency like the DOH does not have the inherent authority to reopen or reconsider a final permit or license condition *sua sponte*. It can reopen a permit only if that specific power is conferred upon the agency by the express terms of the statute creating the agency,[1] or if a

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[1] See, e.g., Pacheo v. Clark, 44 Cal. App. 2d 149, 112 P.2d 67 (1941) (absent clear intention of the legislature to vest agency with continuing jurisdiction, the Agency had no power to alter or modify its orders).

substantial change in circumstances or fraud is shown.[2] Moreover, to the extent that an agency's authority to modify an effective permit or license is unclear, the presumption must be that the agency does not have such authority.[3]

The following sections summarize the facts of this case and then set out the limits of DOH's "rereview" authority under state law.

A. Summary of the Facts

The BACT limits in the IGS permit were established in the June 1980 U.S. Environmental Protection Agency (EPA) prevention of significant deterioration of air quality (PSD) permit and in the December 1980 DOH air quality approval order. The BACT limits were based upon comprehensive analyses

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2/ Cf. Clean Air Act § 307(b)(1); Oljato Chapter of Navajo Tribe v. Train, 515 F.2d 654, 662 (D.C. Cir. 1975) (new information may cast doubt on validity of order that was valid when issued); Carisso v. McGoldrick, 133 NYS2d 531 (1954) (stating that fraud is inherently a sufficient basis for review by an administrative body of its own order.); Miles v. McKinney, 174 Md. 551, 199 A. 540 (1938); Atlantic Refining Co. v. Zoning Board of Appeals, 142 Conn. 64, 111 A.2d 1 (1955); Willmont Liquors, Inc. v. Rohan, 2 Misc. 2d 768, 149 NYS2d 874 (1956) (reversal by the State Liquor Authority of its determination denying an application to transfer a license to other premises, which was merely a change of mind unsupported by new or additional evidence, without changed condition, was held to exceed the power of the administrative agency, although the reversal occurred within 8 days of the original determination).

3/ CAB v. Delta Airlines, 367 U.S. 316, 323-25 (1961).

of the emission limits that could be attained by a source making design and procurement commitments in 1980. At the time the permits were issued, though, none of the major control equipment had been selected nor had a boiler manufacturer been chosen. The IPP permit applications indicated that the IPP preliminary design called for a lime scrubber to control SO2 emissions and an electrostatic precipitator (ESP) to control particulate matter emissions. IPP also gave the DOH and EPA preliminary design data on low NOx boilers including a maximum heat input value.

Based on the comprehensive data available concerning emission limits that could be met by a source making design and equipment commitments in 1980, the PSD permit and the state approval order imposed BACT limitations which required (1) for sulfur dioxide, a 90 percent removal and a mass emission limit of 0.15 pounds per million Btu;[4] (2) for particulate matter, a limit of 0.02 pounds per million Btu; and (3) for NOx, a limit of 0.55 pounds per million Btu on a 30-day

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[4] The state approval order established a mass emission limit of 0.155 pounds per million Btu based upon the analysis set out below. The EPA permit set a limit of 0.15 pounds per million Btu basis on rough (now outdated) emission factors. IPP has designed the IGS units to meet the more stringent limit of 0.15 pounds per million Btu.

average.[5/] All the IGS BACT emission limits are more stringent than the limits set by EPA in June of 1979 when, after an extensive rulemaking effort to determine the control capabilities of available technology and the costs of imposing such technology, EPA established new source performance standards (NSPS) for coal-fired power plants.[6/]

After issuance of these EPA and DOH permits, IPP completed control equipment studies, issued bids for the major items of equipment and began the coal procurement process. After discussions with DOH, IPP made final decisions on refinements and modifications to the preliminary design of the control systems for particulate matter and SO2. Specifically, IPP decided to use a baghouse rather than an electrostatic precipitator to control

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[5/]The state approval order NOx BACT limit was 0.60 pounds per million Btu, the same as the applicable new source performance standards; the EPA limit was 0.55 pounds per million Btu. The IGS units will meet the 0.55 pounds per million Btu limit.

[6/]The applicable NSPS for the IGS are set out in 40 C.F.R. Subpart Da, §§ 60.40a-60.49(a)(1982). They were promulgated by EPA in 1979 -- shortly before the EPA and the DOH made their BACT findings for the IGS. 44 Fed. Reg. 33613. The NSPS for SO2 applicable to IGS would require it to meet a percentage reduction standard of 70 percent and would require emissions to be controlled to approximately 0.45 pounds per million Btu heat input. The applicable federal NSPS requires plants like IGS to meet a particulate matter emission standard of 0.03 pounds per million Btu. The applicable NSPS requires new power plants burning bituminous coal (like that burned at IGS) to meet a NOx emission limit of 0.6 pounds per million Btu on a 30-day average.

particulate matter and to use a limestone scrubber rather than a lime scrubber to meet the BACT limit for SO_2. These changes were made in order to provide more reliable and cost-effective compliance with the BACT emission limits in the IGS permits. IPP also selected Babcock & Wilcox as its boiler manufacturer; the final boiler specifications given by Babcock & Wilcox provided for each boiler to have a heat rate that is slightly higher than the one used in the preliminary design.

In contracting for and installing all pollution controls at IGS, IPP relied on the 1980 permitted emission limits; IPP negotiated and received guarantees from control equipment vendors -- guarantees specifically designed to assure that IPP will meet the 1980 stringent BACT limits for all three pollutants. Hundreds of millions of dollars have already been expended to design and construct IGS in order to meet the 1980 pollution control design objectives; on-site construction of both units is well underway. As a result of these irrevocable economic and physical commitments to the 1980 IGS design requirements for control equipment, any significant changes now in the design objectives for major items of equipment or any changes which affect the physical layout of structures or equipment will disrupt construction and can substantially delay completion of the project at tremendous cost.

B. The DOH Does Not Have the Authority to Change the BACT Limits in this Case

The DOH does not have the authority to change the BACT limits in the IGS permit. The Utah Code contains no general provisions expressly allowing the DOH to reopen the BACT terms of its approval orders sua sponte, and the DOH Air Conservation Regulations do not give the DOH blanket authority to reopen approval orders.

The DOH rules on approval orders authorize the DOH to require a source owner to apply for an approval order, and for DOH to issue such an order, only when an owner is (1) planning to construct a new installation; (2) making modifications to an existing installation which modifications will increase the amount or change the effect of, or the character of, air contaminants discharged; or (3) planning to install an air cleaning device or other equipment intended to control emission of air contaminants from a stationary source. Utah DOH Regulation 3.1.1. The first two conditions do no apply in this case, and, as explained below, even if the third condition is applicable, the review is limited to a determination of compliance with the 1980 permit limits.

First, and most important, IPP is not proposing to construct any new installation. IPP has not made any changes in the project which, by any reasonable standard, could be considered to be of the magnitude to constitute the construction of a new installation. As discussed above, the design of the project has matured and, as is true of any major project, differences between preliminary and final design have emerged. Such differences are to be expected, particularly where, as here, very rigorous design objectives are established in the construction permit for the source.[7]

A 1978 EPA memorandum, interpreting the BACT regulations which are now being implemented by DOH, explicitly recognizes that differences between preliminary and final design of the kind involved in this case are to be expected and that they do not constitute a significant change in the project and thus do not trigger new permitting requirements and reevaluation of BACT limits. As this EPA memorandum explains, when utilities apply for new source permits, they often submit only preliminary design information as a basis for setting BACT limits and then agree to submit final detailed engineering design specifications prior to construction of the control equipment. This was the case with IGS. The memorandum then recognizes that the final engineering design and vendor specifications will often vary from the preliminary information. This also was the case here. These variations, EPA observes in terms that parallel the facts here, may "<u>include basic changes in equipment design</u>

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[7] As noted above, EPA's 1979 NSPS determinations on achievable control levels were virtually contemporaneous with the BACT determinations for IPP. Nevertheless, IPP's BACT limits were in each instance more stringent than the federal NSPS.

such as a shift from an ESP to a baghouse, a change from a lime/limestone scrubber to a regenerable scrubbing system or a change in the design approach to ensuring reliability." (Emphasis added.)

The EPA memorandum goes on to explain that, when there are such variations in final design specifications, the utility must show only one thing -- that the equipment meeting the final specifications is equivalent in performance and reliability to that covered in the initial BACT demonstration. As a result, the authority reviewing the final design information is to "seek only those data elements which are necessary to support an engineering judgment that the proposed system will perform reliably at the specified emission rates." Since the submission of the final engineering design specifications is required, as it is here, EPA then concludes that the submission of such design specifications, "would not constitute a reopening of the permit process, and [would not trigger] the need for an opportunity for public comment on this material."[8/]

In sum, the differences between the preliminary and final design of the IPP control equipment cannot be said to

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8/EPA memorandum on "BACT Information for Coal-Fired Power Plants," sent from Walter C. Barber to the EPA Regional Offices (December 22, 1978). A copy of this memorandum is Attachment 8 of this Position Paper.

re-open the permit process on the ground that IPP is constructing a new installation that was not previously permitted.

Nor can the refinements in design of the boiler be said to constitute a "modification" of an existing source, triggering new BACT review. Under Utah law, there is no modification unless there is a potential increase in emissions from a "source." Utah DOH Regulation 1.1.77. Under the definition of "source" in the Utah Air Conservation Regulations, IGS is one source.[9] Thus, it is an increase in total emissions at the IGS which would constitute a modification under Utah law. If IGS increases emissions at individual emission units within the project and offsets those increases by decreases at other project emission units, IGS would not be considered a modified source.

IPP is not proposing to increase emissions at IGS. While the boilers will have a slightly higher heat rate than originally anticipated and therefore may produce more NOx

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[9] Under the Utah DOH Regulation 1.1.111, a "source" means "any structure, building, facility, equipment, installation or operation (or combination thereof) which emits . . . any air pollutant and which is located on one or more contiguous or adjacent properties and which is owned by the same person . . . ." Intermountain Generating Station -- including the boilers and associated control equipment -- is all on the piece of property and is under common ownership and thus constitutes one "source" under Utah law.

emissions on a per unit basis than would be produced if there were a lower maximum heat rate, total emisions from the source will be significantly less than described in the original application for an approval order for IGS. On March 31, 1983, the size of the project was officially reduced from four to two generating units, cutting potential emissions from the source almost in half.

In sum, it is a net increase in emissions at the "source" (which in this case is a multi-unit generating station) that triggers the modification requirements of the DOH regulations. The total emissions at the IGS "source" are, as a result of the changes between preliminary and final design, almost one-half of the emissions permitted in 1980.

Finally, there is the issue of whether the DOH has approval order review authority because IPP is planning to install different air cleaning devices -- i.e the baghouse and limestone scrubber -- than were originally proposed. For the reasons stated in the 1978 EPA memorandum discussed above, these devices should not be viewed as triggering a new BACT review since the differences between preliminary and final design, such as those in this case, are to be expected. Nevertheless, even if a new approval order for the IGS baghouse and limestone scrubber system is required, the agency is not authorized to rewrite BACT terms in connection with issuance of that approval order.

Under Utah DOH Regulation 3.1.8, the Executive Secretary is required to issue an approval order if he determines that the control devices are at least BACT and that their installation will be in accord with applicable state and federal rules. As noted above and as described in much greater detail below, the IGS baghouse and limestone scrubber will control emissions at least to the level of BACT; the baghouse will achieve an emission rate of 0.02 pounds per million Btu and the limestone scrubber will achieve an emission limit of 0.15 pounds per million Btu, which is actually lower than the BACT limit set in the DOH approval order. Also, the installation will be in accord with applicable state and federal air quality requirements. Thus, under the terms of the DOH rules, the Executive Secretary is not authorized to revise the BACT limits in connection with his review of the final design of the IGS SO2 and particulate matter control systems.

C. Summary

In sum, IPP received a permit to construct a facility with control equipment that would be designed to assure compliance with the emission limits contained in the December 3, 1980 approval order. IPP is constructing such a facility. IPP recognizes the appropriateness of state review to determine whether the final design of the control equipment will in fact assure compliance with the 1980 BACT limits. Where, as here, there is no net increase in facility emissions as a result of changes in design, there is no basis in Utah law for establishing new BACT limits that differ from those previously established.

III. The Current Emission Limits Constitute BACT

Although IPP believes that it is inappropriate to conduct a BACT re-review for a project that, in good faith, has made commitments to equipment that will assure compliance with the BACT limits that were properly set at the time of permitting, IPP has prepared data which demonstrate that the current permit limits represent BACT for the IGS. The following sections summarize the legal framework for a BACT review and then apply that framework to the facts in this case.

A. What Is BACT?

Federal law and the Utah Air Conservation Act call for the application of BACT for reduction of certain regulated pollutants -- in this case, SO2, NOx, and particulate matter. Under Clean Air Act section 169[10/] and Utah DOH Regulation 1.1.23, BACT for a pollutant means an emission limit for that pollutant reflecting the maximum degree of reduction that is achievable taking into account energy, environmental, economic and other impacts. Each BACT determination is to be made on a

[10/] 42 U.S.C. § 7469(3)

case-by-case basis, although the application of BACT may not result in pollutant emissions in excess of applicable emission levels established pursuant to Clean Air Act section 111.

Federal and state law thus ask the permit issuer, in setting BACT limits, to consider on a case-by-case basis what is achievable, environmentally sound, and cost-effective. A significant body of federal case law explains what is meant by the term "achievable" and how energy, environmental, and economic costs are to be taken into account on a case-by-case basis. In the context of this case, DOH may rely upon the record supporting the 1980 BACT determinations in deciding not to change those limits. On the other hand, if the BACT limits were changed, DOH would have to demonstrate that it considered relevant factors and disclosed and explained fully the basis for its change of course. If the record does not contain such an explanation or if the facts do not support the DOH conclusions, a court would conclude that the new limits are arbitrary and capricious.[11/] The following discussion explores the burdens DOH must bear in order to support any more stringent BACT limitations.

[11/]Motor Vehicles Mfrs. Ass'n. v. State Farm Mutual Ins. Co., 51 U.S.L.W. 4953, 4955 (U.S. June 24, 1983) (No. 82-354) ("an agency changing its course. . . is obligated to supply a reasoned analysis for the change beyond that which may be required when an agency does not act in the first instance").

1. Demonstrating Achievability

On the matter of "achievability," the case law makes it clear that when a decisionmaker projects that a certain emission limit is achievable, his decision must meet the following criteria:

> (1) The decision must specify the precise data and assumptions on which the decisionmaker's projections are based and establish the reasonableness and reliability of the methodology.[12] The decision may not rely on "crystal ball" inquiry or extrapolate from "purely theoretical or experimental" technology.[13]
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> (2) Where the decision is based on a projection that an as-yet-undemonstrated technology will work in the future, that projection must be able to withstand close scrutiny. There may be room for a projection that a certain technology will eventually be adequate to achieve a particular emission reduction if that technology is to be installed by sources several years in the future; however, if a standard is set based on a technology that is to be installed immediately, then "the latitude [given to the] projection is correspondingly narrowed."[14]
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> (3) If the BACT decision is based on data from a test facility, the analysis supporting the

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12/Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375, 391-93 (D.C. Cir. 1973); International Harvester Co. v. Ruckelshaus, 478 F.2d 615, 642-43, 647-48 (D.C. Cir. 1973).

13/Portland Cement, 486 F.2d at 391-92.

14/Id. at 391-92. Since IGS is under construction and any change in design must be implemented immediately, there is little or no latitude for projection.

decision must consider the possible impact on emissions due to recognized variations in operation when the technology is applied in full-scale, commercial practice and must offer some rationale for the achievability of the standard in light of those variations.15/ The conditions under which tests are conducted for purposes of standard development should be similar to the conditions specified for enforcement.16/ Thus, for example, the court carefully scrutinized an Agency conclusion that a technology would work at full load operation when the facilities being tested were operating only at approximately 52% of capacity.17/

In short, in making a BACT determination a decisionmaker can hold a source to a standard of improved design and operational advances only where (1) there is "substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard,"18/ and (2) the decisionmaker sets out that substantial evidence

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15/National Lime Ass'n v. EPA, 627 F.2d 416, 434-43 (D.C. Cir. 1980).

16/Portland Cement, 486 F.2d at 396.

17/Essex Chemical, 486 F.2d at 436.

18/Sierra Club v. Costle, 657 F.2d 298, 364 (D.C. Cir. 1981); Bethlehem Steel v. EPA, 651 F.2d 861, 876 (3d Cir. 1981). IGS, of course, is no longer a "new source." Construction is underway and substantial commitments have been made to meet the 1980 design objectives established by the DOH and EPA. In this setting, changes in design are much less feasible and improvements in performance much less certain than in the case of standards set for new sources that will be designed and constructed after establishment of the standards.

clearly and precisely for the record.[19] In sum, the burden is on DOH to establish the technical basis for any determination that a particular emission limitation is achievable.

2. Demonstrating that a BACT Limit is Cost-Effective

Finding that a particular technology is demonstrated and that a specific emission level is achievable represents only the starting point for a BACT determination. Each achievable level of control must be evaluated in light of its economic costs, energy requirements and environmental implications. The level of control representing "best" technology must therefore reflect a balancing of factors, including the costs associated with achieving emissions reductions. A control technology will be "best" technology only if it is a cost-effective control technology and reflects a balancing of the statutory factors. When technology is being applied in a "retrofit" context, -- *i.e.*, when the technology is not part of the original design and thus its installation requires changes to be made to the original design -- then cost considerations may justify substantially less stringent limitations than would be

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[19] Portland Cement, 486 F.2d at 391-92.

appropriate for a new facility.[20]

3. Making a Case-by-Case Determination

Finally, the law emphasizes the need to make each BACT determination on a case-by-case basis. In determining appropriate emission levels, the decisionmaker must keep in mind that BACT emission levels may be no less stringent than the levels established by applicable new source performance standards (NSPS) set under Clean Air Act section 111, but that the BACT levels are indeed set case-by-case taking into account the characteristics of the specific source.[21] As a result, what may be applicable to most plants, may not be appropriate

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20/Cf. ASARCO Inc. v. EPA, 578 F.2d 319, 330-31 (D.C. Cir. 1978) (Leventhal, J., concurring) (in setting new source performance standards, the EPA Administrator may set less stringent standards for modified sources -- e.g., retrofit sources -- than for new sources since such distinctions may be "warranted by cost differences and cost-benefits analysis"). The visibility protection provisions of the Clean Air Act reflect the importance of balancing all relevent factors in a retrofit situation to avoid the imposition of improper control requirements. Under § 169(g)(2) of the Act, when the states specify "best available retrofit technology" ("BART") for sources impairing visibility in class I areas, emission limits are to be based on the consideration of the cost, affordability, adverse side effects, and efficiency of alternative control options. Section 169A(g)(2). EPA's BART regulations expressly acknowledge that the "best" technology is not necessarily the one that removes the most pollution. EPA, Guidelines for Determine Best Available Retrofit Technology for Coal-Fired Power Plants and Other Existing Stationary Facilities," EPA-450/3-80-0096 and pages 20-21 (Nov. 1980)(incorporated by reference into 40 CFR §§ 51.300-307 (1982)).

21/Northern Plains Resource Council v. EPA, 645 F.2d 1349, 1358-62 (9th Cir. 1981.)

for a particular facility[22] -- e.g., as in the case of IGS where, if any new technology is required, it would not be part of the original plant design and therefore would be a retrofit. Specifically, if adding a new technology would involve a great deal of additional expense to reduce already well controlled emissions, the new technology should be rejected as BACT.[23]

B. Application of the BACT Criteria to IGS

If we apply the BACT standards to the facts of the IPP case, it is clear that the current emission limits represent BACT. The following subsections summarize the BACT data submitted by IPP and apply the BACT standards to those data.

1. The Current SO2 Emission Limits Represent BACT

a. The Permitted SO2 Limits

IPP must achieve a 90 percent reduction of SO2 emissions, and must meet a mass emission standard of 0.15 pounds of SO2 per million Btu heat input.[24] Compliance

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22/ Id. at 1359 n.29.

23/ Cf. Northern Plains, 645 F.2d at 1361.

24/ As noted above, the federal new source performance standards for SO2 applicable to IGS would require it to meet a percentage reduction standard of 70 percent and would require emissions to be controlled to approximately 0.45 pounds per million Btu heat input. The permitted SO2 limits for the IGS units are thus significantly more stringent than the federal NSPS.

with these requirements will be determined using continuous monitors and 30-day rolling averages.25/

The extremely stringent percent removal standard goes well beyond the federal NSPS standard of 70 percent. In 1979, EPA determined that that level reflected the most cost effective technological standard for low sulfur coals. The 90 percent removal standard imposed in its permit requires IPP to design a system which approaches the limits of the demonstrated removal capabilities of SO2 scrubbers. To meet this condition, IPP contracted to purchase and build a state-of-the-art limestone scrubber. This scrubber has been carefully designed so that it can comply with the standard while burning all of the various Utah coals planned for use at IGS.

The mass emission limit of 0.15 pounds of SO2 per million Btu is also one of the most stringent in the country. The mass emission limit was set based upon information estimating the sulfur content of the coals to be burned at IGS and then assuming that 90 percent of the SO2 would be removed by the scrubbers. The mass emission limit for SO2 is thus based in large part on the sulfur content of the coal to be burned.

25/The state approval order established a mass emission limit of 0.155 pounds per million Btu based on the analysis set out below. The EPA permit sets a limit of 0.15 pounds per million Btu based on rough (now outdated) emission factors in AP-42. IPP has designed IGS to meet the more stringent limit of 0.150 pounds per million Btu.

In its PSD permit application, IPP discussed the sulfur content of the coal it would burn at IGS and used estimates of coal characteristics. Estimates, rather than actual data, were required because IGS is not a mine-mouth plant and thus, at the time of permitting, it was not clear what coal would be burned. IPP based its coal quality information on core hole sample data from existing mines and leases located in the Northern Wasatch Plateau and the Book Cliffs coalfields. Adjusting that core hole data to reflect worst case conditions, IPP estimated that it would be getting coal with an average Btu content of 10,200 and average sulfur content of 0.79 percent. The DOH SO2 mass emission limit was set based on those coal quality estimates and on the assumption of 90 percent SO2 reduction through a scrubber. IPP accepted the permit conditions based on these estimates and this assumption.

Having once accepted that mass emission limit, IPP then took steps to assure that the coal purchased would comply with the limit. To accomplish this, IPP's coal contracts all include guarantees for coal qualities that the purchased Utah coal must meet. The contracts provide a range of sulfur in the coal and a typical sulfur content. As a result of normal sulfur variability in coal, some of the coal is likely to be higher in sulfur content than 0.79 percent; some is likely to be lower. IPP is aware of this, and the scrubber system has been designed so that the SO2 emissions from the coal -- after scrubbing -- will meet the permitted mass emission limit of 0.15 pounds per million Btu on a 30-day rolling average basis.

In summary, the IGS SO2 emission control system has been very carefully designed to ensure that 90 percent SO2 reduction can be achieved on a 30-day average and that the total mass SO2 emission limit of 0.15 pounds per million Btu can be met using the Utah coal which IPP is required to burn at IGS and which IPP has contracted to purchase.

b. Obstacles to Achieving More Stringent SO2 Limits

Although the IGS scrubbers have been designed to reduce SO2 emissions by 90 percent during the 35-year life of the plant, the DOH's June 8, 1983 letter asks IPP to evaluate the cost of a "95% SO2 scrubber." In addition, at a July 6, 1983 meeting, DOH representatives asked IPP to evaluate the possibility of IGS' meeting a mass emission limit of 0.14 pounds per million Btu. The following discussion summarizes problems associated with making any changes to the 90 percent standard or the 0.15 mass emission limit.

(1) The 90 Percent Standard

There are serious obstacles to achieving a 30-day average 95 percent reduction rate over the entire 35 year lifetime of a power plant. As stated by Black & Veatch in its report, "Cost Analysis of Various NOx and SO2 Control

Technologies for the Intermountain Power Project," which was submitted to DOH on June 22, 1983, 90 percent SO2 removal on a 30-day average basis is the upper limit which limestone scrubbers have been demonstrated to achieve. Although wet limestone scrubbers are capable of achieving SO2 reductions in excess of 90 percent for short durations, extended operation in excess of 90 percent has not been demonstrated at any operating facility. The Black & Veatch Report explains that the major obstacle which prevents a scrubbing system from continuously achieving SO2 removal efficiencies in excess of 90 percent is the system's inability to catch up for periods of reduced SO2 removal rates caused by such factors as inherent system variability, component failures, and system chemistry upsets.

For instance, if a scrubbing system designed for 90 percent SO2 removal achieved only 70 percent removal for 10 hours due to a component failure, it would then have to be operated at 95 percent removal for 40 hours in order to average 90 percent removal over a 30-day period. However, if a scrubbing system designed for 95 percent SO2 removal experiences a component failure which causes it to operate at 70 percent removal for 10 hours, it will require that the system be operated for 125 hours at 97 percent SO2 removal to achieve an average SO2 removal of 95 percent. Should multiple component failures occur in a 30-day period, then it may be impossible for the scrubbing system to achieve an average of 95 percent design SO2 removal even if it could be operated at 100 percent SO2 removal.

In sum, extended operation at 95 percent SO2 removal has not been demonstrated in practice. However, even if such a limit were achievable, it would not be BACT unless it could be achieved in a cost-effective manner. Thus, the limit must be evaluated in light of its economic costs, energy impacts, and environmental implications.

The Black & Veatch Report evaluates the costs of a scrubber system designed for 95 percent reduction. If IPP were to retrofit IGS with such a 95 percent design SO2 removal system before the start of commercial operation, the Black & Veatch Report estimates that the additional capital costs, operating costs, and delay costs associated with retrofitting such a system would be $998 million (in 1986 dollars); the additional cost would be $1.118 billion (in 1986 dollars) for retrofitting the 95 percent design SO2 system after one year of commercial operation.[26/]

[26/] Costs for implementing a 95 percent design SO2 removal system contained in this study are based on more detailed engineering analyses, more refined estimates of replacement power costs and other costs of delay, and a more sophisticated technique for projecting capital costs than those used in earlier analyses. As a result, these estimates are more accurate than, and supercede, those contained in the Black & Veatch memorandum to Intermountain Power Project dated April 13, 1983.

The report explains that those costs were estimated based on the assumption that, for a scrubbing system to achieve an average SO2 removal rate of 95 percent, enough redundancy must be available to dampen normal scrubber operational variability and to eliminate all avoidable outage time. The Black & Veatch Report concludes that the only way to approach this undemonstrated removal level is to install an extensive number of spare components -- for example, four additional absorber modules and an additional spray level for each absorber module. Also, there would have to be changes made in the current scrubber design to accommodate the additional equipment. The cost estimates also took into account the fact that if a decision is made to retrofit a 95 percent design SO2 removal system on July 1, 1983, then a project delay of 18 months is expected. A decision to implement a retrofit of a 95 percent design SO2 removal system following one year of operation would also require a unit outage of approximately 18 months. All these factors contribute to the approximately $1 billion scrubber retrofit costs.

An examination of the cost per ton of SO2 removed dramatically demonstrates that the incremental cost of designing a "95 percent scrubber" is not justified. Black & Veatch has estimated, for the 90 percent scrubber, that for each unit it will remove 23,200 tons of SO2 annually at an average cost of $1,260 per ton of SO2 removed. However, if a 95 percent scrubber is installed and if it is able to achieve 95 percent removal, it would only remove an additional 1,300 tons of SO2 annually at each unit. The cost to remove this additional 2,600 tons would be $50,600 per ton. This is an exorbitant price to pay for slightly lower SO2 emissions. In setting a revised NSPS in 1979, for example, EPA rejected proposals that would have cost in the range of about $2,000 to $2,500 per ton.27/

There is also an energy penalty associated with operating a 95% scrubber. Operating a 90 percent scrubber will consume 3 to 5 percent of the total plant electrical output. Operating a 95 percent scrubber will nearly double the energy consumed by the scrubber equipment, and will add $63.5 million to costs of operating the scrubber.

In summary, evidence submitted by IPP shows that removal of greater than 90 percent of SO2 emissions on a continuous basis for the life of IGS has not been demonstrated to be achievable. Moreover, to purchase, install, and operate a scrubbing system designed to approach 95 percent removal (whether it is retrofitted now or after commercial operation) would cost approximately $1 billion, and over $50,000 for each

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27/45 Fed. Reg. 8219, Table 3 (1980); 44 Fed. Reg. 33607, 33609, Table 5 (1979). The costs reported in the text are July 1, 1986 costs; they have been scaled up from the 1978 costs used by EPA when issuing the revised NSPS.

additional ton of SO_2 removed. Under the statutory and regulatory criteria to be followed in setting BACT, therefore, the 90 percent SO_2 removal requirement is BACT; no more stringent standard is supported by the facts.

2. Obstacles To Achieving a Standard More Stringent than 0.15 Pounds Per Million Btu

The mass emission limit of 0.15 pounds per million Btu also represents BACT. As noted above, that number was based on the assumption that IPP would burn a variety of Utah coals and reflected coal quality data from the most likely sources of Utah coal. Since the time that the SO_2 limit was set, IPP has entered into four coal contracts. Those contracts specify characteristics that all delivered coal must meet. The contract terms assure that IPP will be able to meet the 0.15 mass emission limit but do not ensure compliance with any more stringent limit. Specifically, the four existing coal supply contracts limit sulfur content to an average "worst case" sulfur limit of 0.733 pounds of sulfur per million Btu, which corresponds to an SO_2 emission rate of 0.147 pounds per million Btu when the scrubber operates at 90% removal efficiency.[28/] Economic penalties will apply to any coal supplier that does not

[28/]One of the four contracts limits coal to a sulfur content of 0.760 pounds per million Btu, corresponding to an SO_2 emission rate of 0.152 pounds per million Btu if the highest conforming sulfur content coal were burned. Over the permitted 30-day averaging period, however, lower sulfur coal would be burned, assuring compliance with the 0.15 limit.

conform to the contractual sulfur content limits.

In the immediate future, coal suppliers will not only be delivering marginally complying coal, but also will be delivering lower sulfur content coal so that the plant will often be achieving an emission rate lower than 0.15. However, over the life of the plant, taking into account future SO_2 emission regulatory requirements, there is likely to be an increased demand and a higher price for lower sulfur coals. Thus, it is likely that, during the life of the IGS units, all Utah coal suppliers will have an economic incentive to deliver only marginally conforming coals under existing contracts. If this happens, it could become impossible for the IGS units to comply with an SO_2 emission limit below 0.15 unless new contracts for lower sulfur coal could be negotiated. Since the annual fuel cost for the IGS units is estimated to be well over $100 million, the additional cost to the IPP for negotiating new lower sulfur coal supply contracts for the life of the IGS units could easily be several hundred million dollars.

Also, the imposition of a lower emission limit would shift liability for compliance from the SO_2 scrubber manufacturer and coal suppliers to the IPP. This new risk could result in higher bonding interest rates and substantially higher financing costs. Since the Project has a remaining bonding requirement of approximately \$3.4 billion, an increase of one percent in the bonding rate would result in an additional cost of over \$100 million.

Although the costs of lowering the SO2 emission limit from 0.15 to 0.14 are very high, the benefits associated with such a permit change are minimal. To meet the current SO2 limit of 0.15, IPP will be removing approximately 46,000 tons of SO2 annually; shifting coals to achieve the marginally lower emission rate of 0.14 would further reduce annual SO2 emissions by no more than 340 tons. In fact, the actual annual reduction is likely to be far less, since IPP would, at most, be changing only a portion of its coal supplies to meet the 0.14 limit, and since the annual average sulfur content of coal delivered under renegotiated contracts may not be reduced significantly.

The SO2 ambient air quality standards and PSD increments are thoroughly protected with the current 0.15 limit. For example, the maximum 3-hour predicted IGS impact is 80 ug/m^3, which is less than 20 percent of the applicable PSD increment; when plant impact is added to the 3-hour background concentration of 26 ug/m^3, the maximum 3-hour ambient concentration is 106 ug/m^3, which is still less than 10 percent of the 3-hour secondary standard of 1300 ug/m^3. The IGS maximum 24 hour impact (32 ug/m^3) and the annual impact from the plant (1 ug/m^3) are also well below the applicable ambients standards and PSD increments.

If the IGS limit for SO2 were lowered to 0.14, that would not significantly reduce the maximum SO2 concentrations from the plant. Specifically, the maximum 3-hour SO2 plant impact would be reduced by less than 6 ug/m^3, the maximum 24-hour plant impact would be reduced by less than 2.5 ug/m^3, and the annual plant impact would be reduced by less than .1 ug/m^3. These reductions are all insignificant under criteria established by EPA,[29/] and are probably undetectable by air quality monitors. Thus, the virtually nonexistent air quality benefits of lowering the SO2 emission limit to 0.14 clearly do not justify what may be extremely high costs.

Not only are the air quality benefits negligible, but such a condition might run counter to more important air quality objectives of the state. For example, if IPP were required to meet the 0.14 limit, it would, as noted above, probably have to shift to using other, lower sulfur coals. This could result in Utah's lowest sulfur coal reserves being consumed at the remote and highly controlled (90% removal) IPP instead of at the uncontrolled and less effectively controlled emission sources that are proximate to Utah's population centers.

29/ See 43 Fed. Reg. 26398 (1978), where EPA stated that the minimum amount of ambient impact that EPA would consider significant for SO2 would be 25 ug/m^3 for the 3-hour averaging time, 5 ug/m^3 for the 24-hour averaging period, and 1 ug/m^3 annually.

Finally, in response to the DOH suggestion that IPP can meet the 0.14 limit because other utilities have accepted limits lower than 0.14 pounds per million Btu, it must be noted that limits lower than 0.14 have been accepted only in cases where the affected utilities have been virtually certain that they will, over the life of the affected units, be able consistently to acquire coal with a lower sulfur content than that now under contract to IPP. For example, a mine-mouth unit or other unit that is getting virtually all its coal from one source of very low sulfur coal may be able to meet an emission limit lower than 0.15 pounds per million Btu. We understand that this is the case for Utah Power & Light's Hunter Units 3 and 4, which are mine-mouth units.30/ Very low limits may also be achievable where new units are being built at a site where there are already other units subject to less stringent SO2 limits. At such sites, delivered coal with the lowest sulfur content can be burned at the new unit with the lowest SO2 limit; any higher sulfur content coal can be burned at the other units at the site. Thus, on a

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30/It should also be noted that Brigham Young University and Kennecott Corporation each get most of their coal from a single source. The small Brigham Young University boiler uses only one source of low sulfur coal, and the Kennecott Corporation facility gets at least two thirds of its coal from one source of very low sulfur coal.

case-by-case basis it may be appropriate to require these types of sources to meet emission limits lower than 0.15 pounds per million Btu. Since the same circumstances do not apply at the IGS units, it is not appropriate to reduce the SO2 mass emission limit below 0.15.

In summary changing the 0.15 pounds per million Btu mass is unjustified. It would be extremely costly and disruptive, would yield no significant environmental advantages, and would not take into account the coal contract situation at the IGS units. Thus, under the current statutory criteria for setting BACT, the current limit is BACT and should not be changed.

3. The Current Particulate Matter Emission Limit Represents BACT

The applicable federal NSPS requires plants like IGS to meet a particulate standard of 0.03 pounds per million Btu. As with the limits on SO2, the permitted particulate matter emission standard for the IGS units is more stringent than the federal NSPS. Indeed, the IGS limit of 0.02 pounds per million Btu is one of the most stringent particulate matter emission standards set for any power plant in this country and reflects the maximum degree of particulate matter reduction that can be achieved at the IGS units.

Before contracting for the purchase of particulate control equipment to meet that stringent limit, IPP studied the capabilities and costs of both electrostatic precipitators and baghouses. An April 1980 analysis conducted for IPP, entitled "Study for Particulate Control Equipment -- Electrostatic Precipitators and Fabric Filters -- Intermountain Power Project" (Attachment 4), examined both particulate collection devices and concluded that baghouses were preferable for IGS for several reasons. First, precipitator design is closely tied to coal, ash and flue gas properties; where several coals are to be burned (as is the case at IGS), designing a precipitator is difficult and expensive. If, some time during the 35 year operating life of the plant, different quality coals have to be burned, the precipitator might not be able to meet the permitted emission limit. Baghouses, however, are less affected by variations in coal, ash, or flue gas properties. The report also concluded that opacity is better controlled by baghouses, that fine particulates are better controlled by baghouses, and that a baghouse is often easier to maintain online than is a precipitator. Finally, the report concluded that it would be more cost effective to install a baghouse than a precipitator at IGS.

IPP discussed the choice of baghouse with DOH representatives and met with DOH representatives on February 5, 1981 to explain in greater detail IPP's decision to purchase a baghouse. The system that has been purchased is consistent with that previously discussed with DOH. It is one of the most advanced baghouse systems available; the manufacturer has guaranteed that the baghouse system will limit the total particulate emission rate of not more than 0.02 pounds per million Btu heat input. In sum, the current particulate limit represents BACT and the IGS baghouse can achieve compliance with that limit.

4. <u>The Current NOx Emission Limit Represents BACT</u>

a. <u>Achieving the BACT Limit</u>

The applicable federal NSPS requires new power plants burning bituminous coal (<u>i</u>.<u>e</u>., the coal to be burned at IGS) to meet a NOx emission limit of 0.6 pounds per million Btu on a 30-day average. Based on the federal NSPS (which had been revised just a short time before the permitting of IGS), the Utah DOH set a 0.6 pounds per million Btu NOx emission limit in its December 1980 approval order. However, under the terms of its federal PSD permit, IPP is required to meet a NOx emission limit of 0.55 pounds per million Btu on a 30-day average. According to a survey conducted by the Utility Data Institute (see Attachment 6), no more stringent NOx emission limit has been imposed on any power plant burning bituminous coal.

In setting the 0.55 NOx limit, EPA's technical experts indicated that this represented the most stringent limitation that could be justified by available data. Letter from J. Burchard, Director, U.S. EPA IEAL, to R. L. Duprey, Director, U.S. EPA Air and Hazardous Waste Division, April 21, 1980. There are plants that have agreed to meet more stringent NOx emission limits, but those plants are burning subbituminous coal, which is less likely to cause corrosion, slagging and fouling. In setting the NSPS for power plants, EPA recognized that it was appropriate to set lower limits for users of subbituminous coals.

As described in KVB's report, "Technical Evaluation of Alternative NOx Control Technologies," IPP has contracted for the purchase of a boiler that is designed and guaranteed by its manufacturer to achieve the 0.55 pounds per million Btu, 30-day average NOx emission limit. The boiler selected by IPP is one of the most advanced second generation NSPS boilers available to the utility industry. The boilers for IPP Units 1 and 2 are Babcock & Wilcox (B&W) natural circulation, balanced draft, single reheat boilers, described in the KVB report. The boilers incorporate a burner system designed by B&W to operate at low levels of NOx without creating adverse side effects. The system incorporates a compartmented windbox for precise control of the combustion air and a low-NOx burner design developed by B&W. The B&W dual register burner provides the control of stoichiometry and the mixing of fuel and air necessary to achieve extremely low levels of NOx emissions. The windbox and burner combination is one of the most advanced systems in the industry and has been used on a large number of new second-generation boilers designed to comply with the revised NSPS for both subbituminous and bituminous coals. This system has the most demonstrated experience of the new low-NOx designs.

IPP has also gone to great lengths to maximize the availability and reliability of these units. A separate report entitled, "The Specification and Design of High Availability Boilers for the Intermountain Power Project" describes in detail the considerations that went into the selection of the boilers and their auxiliaries. The boiler was designed to fire Utah bituminous coals having a wide variety of properties. These coals have slagging and fouling tendencies which range from high to medium slagging and from low to medium fouling. The integrated burner and boiler design was selected taking these conditions into consideration. The experience of other utilities with the B&W integrated boiler and burner design will not only ensure high reliability and availability, it also ensures the highest probability of compliance with the NOx emission regulation of 0.55 pounds per million Btu imposed by the EPA PSD review.

b. Obstacles to Achieving a Lower NOx Emission Rate

The DOH, in its June 8, 1983 letter, asked the IPP to investigate five additional NOx reduction techniques: Selective Catalytic Reduction (SCR), Thermal DeNox, Overfire

Air Ports, Lower Excess Combustion Air, and Decreased Plan Heat Releases Through Boiler Derating.

In addition, at a July 6, 1983 meeting, DOH representatives suggested that IPP investigate the possibility of meeting a NOx limit of 0.50 pounds per million Btu with the current boiler design. As a part of this evaluation, DOH asked IPP to review data from two operating plants (the Mill Creek Plant and A.B. Brown Plant), plants which the DOH identified as meeting emission limits lower than 0.55 pounds per million Btu. The KVB Report and a Black & Veatch Report on the cost of NOx controls evaluate the first five NOx reduction techniques. (These two reports were submitted to the DOH in June.) The Supplemental KVB Report, entitled "Review and Evaluation of Mill Creek Unit 3 and A.B. Brown Unit 1 NOx Data" (Attachment 1 hereto), evaluates the NOx emission levels at the Mill Creek and A.B. Brown plants and the achievability of a 0.50 NOx standard with the current boiler design.

The first KVB Report demonstrates that the NOx technologies about which DOH inquired either are not demonstrated or will not ensure further emission reductions for a plant like IGS. Specifically, the KVB Report concludes that:

1. The SCR process has not been demonstrated to be effective on commercial power plants either in systems using a baghouse, or on coals containing the catalyst poisons sodium, potassium, and calcium in the quantities present in Utah bituminous coals. With these coals, the

reliability and availability of the SCR would be seriously jeopardized. The SCR process has therefore not been developed to the point where, if applied to IPP, there is any certainty that it could achieve reliable, continuous reductions in NOx emissions.

2. Thermal DeNOx is an experimental technology on coal and has never been demonstrated to be effective on a coal-fired utility boiler. Therefore,it should not be considered for application at IPP.

3. There is insufficient long-term data to justify retrofit of overfire air ports. The NOx reductions associated with such a retrofit are uncertain, whereas installing overfire air ports could jeopardize the availability and reliability of the boiler as well as the baghouse. The low-NOx burner system incorporated into the present IPP design are capable of yielding low NOx without these adverse side effects.

4. The manufacturer of the IPP boilers incorporates low NOx burners that operate at the minimum practical excess air levels. These burners are proven in use on the type of boiler to be built for IPP. No combustion technology is available for achieving further reductions in excess air without causing unacceptable side effects such as slagging, reduced steam temperature, and loss of fuel efficiency. Further reduction in excess air levels is therefore not practical.

5. Decreased plan heat release through boiler derating has not been consistently demonstrated to yield NOx reductions, and in any case, cannot be considered new technology for the purpose of BACT review.

The Black & Veatch Report demonstrates that even if any of the above technologies could operate reliably and produce significant emission reductions, they would be extremely costly to retrofit at IGS -- either now or some time after plant start-up. For example, as set out in the Black & Veatch

Report, the cost of selective catalytic reduction is estimated to be $1.694 billion (1986 dollars) if retrofitted before commercial operation of IGS and $1.255 billion (in 1986 dollars) if retrofitted at a later time.

The Supplemental KVB Report evaluates the emission data from two operating plants -- Mill Creek and A.B. Brown -- that burn bituminous coal and that have attained emission levels lower than 0.55 pounds per million Btu. The Supplemental KVB Report demonstrates first that there is no valid basis for assuming that the changes in boiler operation discussed in an Exxon report on the Mill Creek data will produce NOx emission levels lower than 0.55 pounds per million Btu at IGS. Second, the Supplemental KVB Report shows that although when Mill Creek operates at fairly low loads it can attain an emission level of less than 0.55 pounds per million Btu, when the Mill Creek unit operates at higher loads, NOx emissions increase. A statistical analysis of the Mill Creek data indicates that if that plant were to operate at close to full load -- as the IGS units will be operated -- it would probably not be able to meet an emission level of less than 0.55. In short the Mill Creek data do not demonstrate that units like the IGS units, which will operate at full load, would be able to meet an emission limit lower than 0.55 pounds per million Btu.

The Supplemental KVB Report also analyzes the data on the A.B. Brown plant. It reveals flaws in the NOx monitors at the plant, decreasing the reliability of the NOx data gathered from those monitors. The report also points out that the A.B. Brown boiler is structurally different from the IGS boilers. The A.B. Brown boiler burns low slagging coal. This permits use of division walls in the A.B. Brown unit, which produces a lower heat release rate in the burner zone, thus generally lowering NOx emisson levels. As the Supplemental KVB Report explains, however, IPP uses high slagging coals which, according to Babcock & Wilcox, preclude the use of division walls in the IGS boilers. In short, the A.B. Brown data are flawed and the A.B. Brown boiler is structurally different from those that are being built at IGS. Thus the A.B. Brown data do not support setting an IGS NOx emission limit lower than 0.55 pounds per million Btu.

IPP's contract with its boiler manufacturer guarantees that the boilers will meet an emission limit of 0.55 pounds per million Btu. The Mill Creek and A. B. Brown data do not provide any basis for concluding that the IGS boilers could meet a NOx limit of 0.50 pounds per million Btu with the current boiler design. Therefore, the imposition of an emission limit below 0.55 would shift liability for compliance from the boiler manufacturer to the IPP. As previously discussed on pages 29 and 30, a new risk of this type could result in substantial additional financing costs. Furthermore, the imposition of an emission limit that may be unachievable would require reconsideration of the project's feasibility and could result in cancellation of the IGS unit.

In sum, the current NOx limit of 0.55 pounds per million Btu is achievable and cost-effective. Attempts to install and operate the controls suggested by the DOH could cost up to $1 billion. Furthermore, there is no technical or factual basis for concluding that the IGS boilers, as currently designed, can meet any emission limit lower than 0.55 pounds per million Btu, and imposing any limit lower than 0.55 could jeopardize the financial viability of the project.

c. Response to Comments by Others

Notwithstanding the compatibility of the IGS NOx limits with all air quality requirements of state and federal laws, certain individuals and environmental groups have submitted comments to the DOH expressing concern about the environmental impacts of the IGS NOx emissions. As summarized here and discussed in greater detail in supporting documents, the NOx emissions from IGS will not have any significant adverse environmental impacts; claims to the contrary are without merit.

Several comments suggest that IGS NOx emissions will increase the acidity of precipitation in the geologically sensitive areas of the Wasatch Mountains. These areas of the Wasatch Mountains are 100 miles or more from IGS. In a report prepared by ERT's Dr. George Hidy entitled "Effects of NOx Emissions from the Proposed Intermountain Power Project on

Deposition and Surface Water Acidification in the Wasatch and Uinta Mountains," Dr. Hidy notes that meteorological conditions and terrain are likely to prevent IGS NOx emissions from ever reaching the sensitive areas of the Wasatch Mountains much less affecting the low alkaline surface waters in the Mountains. However, if such emissions do reach the Mountains, their impacts on the Mountains will be minimal.

Snowpack, precipitation and water quality studies conducted in the Wasatch Mountains and summarized by Dr. Hidy indicate that although the Salt Lake City and Provo metropolitan areas (which are relatively near the Mountains) have grown significantly since the 1950s, there is no evidence that increased NOx emissions from those cities' major mobile and stationary sources have caused any changes in the acidity or nitrate concentrations in the Wasatch Mountains. If such nearby major sources of NOx loadings have no measurable impact, then any increases in current NOx emission levels (in the range of 0.8 percent) due to the far distant IGS cannot be viewed as posing any significant threat of increased acidification. Thus, Dr. Hidy concludes that any small changes in atmospheric levels of NO2 or its derivatives from IGS should have negligible consequences with regard to the pH of low alkalinity surface waters in the geologically sensitive regions of the Wasatch Mountains.

Several other charges and concerns raised by the environmental groups are addressed in a letter from James

Bowers (of the H. E. Cramer Co.) to IPP's James Anthony. See Attachment 3. For example, the letter responds to a comment charging that no NOx dispersion modeling has been done for IGS. This is not true. As pointed out in the Bowers letter, the H. E. Cramer Company's dispersion model analyses of the IGS have covered NOx emissions and have confirmed the minimal impact of the IGS NOx emissions. Specifically, those analyses show that even under the conservative assumption that all NOx emissions from the plant are converted to NO2, the maximum annual plant impact, which will occur about 7 kilometers from the plant, will be only 4.3 micrograms per cubic meter -- a small percentage of the NO2 health standard of 100 micrograms per cubic meter. Due to these low impacts and due to the fact that IGS and the Wasatch Front are in different air basins, Bowers concludes that IGS NOx emissions impacts on the distant geologically sensitive areas of the Wasatch Mountains will be negligible.

Another set of comments claims that NOx emissions from IGS will somehow exacerbate ozone levels in the ozone nonattainment Salt Lake City area, which is 100 miles from IGS. When EPA issued the PSD permit for the IGS, however, the Agency stated in the permit that IGS NOx emissions would not cause or exacerbate any violation of any national ambient air quality standard. The emissions from IGS are now approximately one-half of those evaluated by EPA. Moreover, Bowers, in his letter to IPP (Attachment 3), concludes that IGS NOx emissions impacts on the distant ozone nonattainment areas will be negligible.

Finally, the commenters make unsubstantiated claims regarding the effects on public health of the NOx emissions of the IGS. IPP believes that those claims are frivolous for two reasons. First, as noted above, the licenses issued by DOH and EPA for the initial IGS design -- with four generating units -- was based on findings that the IGS emissions would not violate the public health standards. Since then, the IPP has decided to build only two generating units, which will emit substantially less total NOx than the four units originally licensed.

Second, a comparison of the available health literature and the ambient NO2 concentrations to which the IGS will contribute shows that the plant will not threaten public health. IGS will be well within the current annual NO2 ambient standard, and there is no basis for concluding that this standard will not limit peak and long-term NO2 concentrations to levels well below those required to protect the public health.31/ Moreover, modeling analyses of IGS' contribution to short-term NO2 concentrations reveal that no

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31/EPA, "Preliminary Assessment of Health and Welfare Effects Associated with Nitrogen Oxides for Standard Setting Purposes," Draft Staff Paper, e.g. Appendix B (Oct. 1981) ("EPA's NO2 Draft Staff Paper").

NO2 exposures approaching the levels associated with effects on the public health are produced by IGS.32/

Other claims regarding the effects on visibility of the NOx emissions from the IGS have also been made. As noted above, IPP is going forward with the construction of a facility with total NOx emissions much lower than those initially licensed and found to be acceptable with respect to visibility. Moreover, modeling by H. E. Cramer Company, as reported in the Bowers letter, shows that the plant will not impair the visibility in any class I areas. Finally, as discussed above, IGS will meet BACT emission limits for NOx that are the lowest in the country for a plant burning bituminous coal. Even if emissions could be reduced with the application of additional "retrofit" controls, there is no reason to believe that visibility effects, if any, could be

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32/Based on a highly conservative interpretation of the available health literature, EPA's Staff tentatively concluded that infrequent exposures to 1-hour average NO2 concentrations evan as high as 566 ug/m3 should "present minimal health risks to children and other sensitive population groups." EPA's Draft Staff Paper at 51 (emphasis added). Modeling analyses show that using the very conservative assumption that 100% of IGS' NOx emissions are NO2, the maximum one-hour NO2 concentration caused by IGS is 389 ug/m3, a value well under 566 ug/m^3. More realistic modeling assumptions would produce estimates of peak NO2 1-hour concentrations between 52 and 61 ug/m3. It should be noted that the above calculations are extremely conservative because they are estimates of maximum one-hour concentrations and EPA's risk estimates contemplated multiple annual exposures. In short, the IGS NOx emissions do not pose any significant risk to public health.

perceptibly reduced. As EPA explained in publishing regulations for protecting visibility in class I areas, incremental NOx emission reductions "may not be sufficient to achieve any perceptible improvement in visibility."[33]

d. Summary

The current IGS boiler design incorporates the demonstrated and proved NOx control techniques that will meet the permitted NOx limit. The technologies which DOH has asked IPP to evaluate are unproved; as KVB concludes, there is thus no technical or factual basis for concluding that the IGS boilers can meet any emission limit below 0.55 pounds per million Btu. Additionally any changes in the NOx control system will be extremely costly and could jeopardize the financial viability of the project. Finally, the current NOx emission limit adequately protects the public health and welfare. For all these reasons, the current NOx limit -- 0.55 pounds per million Btu on a 30-day average -- is BACT for IGS.

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[33] 45 Fed. Reg. 80087 (col. 1)(1980); EPA, "Guidelines for Determining Best Available Retrofit Technology for Coal-Fired Power Plants and Other Existing Stationary Facilities," Doc. No. EPA-450/3-80-009b at page 13 (Nov. 1980)(incorprated by reference into the visibility rules, 40 C.F.R. § 51.300-307 (1982)). And even these emission reductions were possible only when NSPS was applied to otherwise uncontrolled plants. IGS will be fully controlled.

CONCLUSION

The SO2, particulate matter, and NOx emission limits that IGS is designed to meet represent BACT. No further BACT review is authorized at this time. However, if such a review is conducted, it will show that the current limits are still BACT. The limits for all three pollutants are more stringent than called for by the power plant new source performance standards for coal-fired power plants. In fact, the current standards are among the most stringent in the country.

The current SO2 emission limit requires IGS to achieve a 90 percent reduction in SO2 emissions on a 30 day average and requires IGS to meet a mass emission standard of 0.15 pounds per million Btu. To meet the 90 percent removal standard, IPP has had to purchase a system that approaches the limits of the demonstrated removal capabilities of SO2 scrubbers; IPP has purchased such a state-of-the-art scrubbing system. Achieving any higher removal efficiencies on a long term basis may not be possible; and trying to achieve high reduction levels will cost approximately $1 billion. To meet the 0.15 mass emission limit, IGS has contracted to purchase several sources of low sulfur coal. Imposing a slightly lower mass emission limit on IGS would produce virtually no air quality benefits, but could well result in IPP's having to negotiate new coal contracts, which could cost several hundred million dollars over the life of the plant.

The current particulate matter standard of 0.02 pounds per million Btu is, we believe, the most stringent in the country. To meet it, IGS has installed a state-of-the-art baghouse system. The current limit is BACT.

The 0.55 pounds per million Btu NOx limit for IGS is also the most stringent in the country for power plants burning bituminous coal. Extensive technical and factual data submitted to the DOH demonstrate that there is no basis for concluding that the IGS boilers can meet an emission limit below 0.55 pounds per million Btu. Not only might a lower limit be unachievable, but also it would be extremely costly even to try to meet a lower limit. For example, the cost of selective catalytic reduction is estimated to be well over $1 billion. Imposing a NOx limit lower than 0.55 pounds per million Btu on the IGS units could thus require IPP to reconsider the feasibility of the entire project.

In summary, the record evidence demonstrates conclusively that the current emission limits for the IGS units are BACT. There is no basis for changing them.

Attachment 2

EFFECTS OF NO_X EMISSIONS FROM THE PROPOSED INTERMOUNTAIN POWER PROJECT ON DEPOSITION AND SURFACE WATER ACIDIFICATION IN THE WASATCH AND UINTA MOUNTAINS

ERT Document No. P-B554

June 1983

Prepared for

INTERMOUNTAIN POWER PROJECT
5250 South 300 West
Murray, UT 84107

Prepared by

George M. Hidy

ENVIRONMENTAL RESEARCH & TECHNOLOGY, INC.
2625 Townsgate Road
Westlake Village, California 91361

1. INTRODUCTION

Conservationist groups have recently questioned the level of nitrogen oxide (NO_x) emission control proposed for the Intermountain Generating Station (IGS).[1] This power plant has been designed to incorporate an NO_x control system that will meet an emission limit of 0.55 pounds per million BTU. The groups claim that a more stringent standard must be set in order to prevent an increase in the acidity of precipitation and surface waters in the distant Wasatch and Uinta Mountains (including both transient acidication of surface waters associated with the spring snowmelt and long-term depletion of lake water buffering capacity). Figure 1 shows the relative locations of the IGS and the Wasatch and Uinta Mountains.

Our comments address this issue by considering the available evidence relating to the physical and chemical processes that govern the extent to which the IGS emissions will potentially impact the mountainous receptor areas of concern. The question of NO_x deposition and surface water acidification is discussed in the next section.

2. POTENTIAL CONTRIBUTIONS OF THE IGS TO NO_x AND ACID DEPOSITION.

The following subsections evaluate the level of IGS NO_x and acid deposition impacts in the Wasatch and Uinta Mountains. They conclude that IGS impacts in those areas will be insignificant for several reasons. They also summarize relevant scientific studies on the general lack of evidence of acidity effects in the Wasatch and Unita Mountains.

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[1] For example, Alan Miller 1983. Intermountain Power Project: Ozone and Acid Rain, Uinta News (Utah Chapter, Sierra Club).

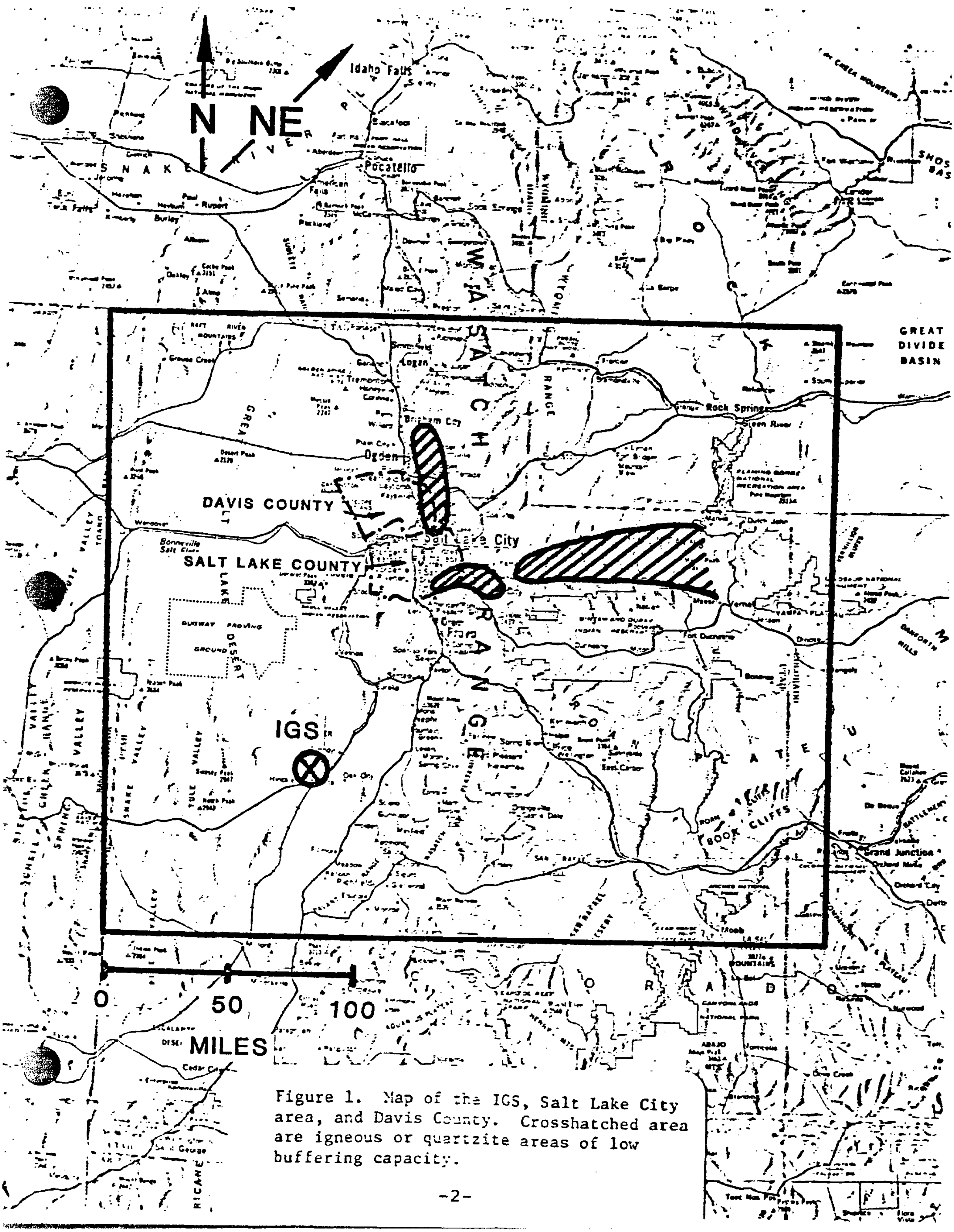

Figure 1. Map of the IGS, Salt Lake City area, and Davis County. Crosshatched area are igneous or quartzite areas of low buffering capacity.

2.1 Dilution of IGS Emissions During Transport

Perspective on the issues relating to the IGS NO_x emissions can be gained by considering the map in Figure 1. The location of the IGS is shown relative to Salt Lake City and the Wasatch Mountains. Lake and watershed areas potentially susceptible to deposition of acidifying substances in the Wasatch and Uinta Mountain ranges are also indicated. These areas have been identified from water alkalinity data, combined with soil and bedrock geology, assuming surface igneous and quartzite rock structure to be an index of low buffering capacity.[2] The locations on the map shows the large distances between the IGS and the receptor areas of concern are one hundred miles or more. Thus, the air containing NO_x emissions from the IGS must travel one hundred miles before becoming involved in atmospheric scavenging processes that produce wet deposition at the ground in the sensitive mountain areas. Note that the parts of the Wasatch Range nearest to the plant site are not considered susceptible by the criteria used. It should also be noted that the cropland and scrubbrush land between the IGS and the mountains are not susceptible to atmoshperic deposition by the criteria used.

The NO_x impacts of potential concern are of two types, corresponding to two temporal scales. The first concerns winter seasonal conditions, where nitric acid derived from oxidation of NO_2[3] will be scavenged and deposited in the snowpack. The second involves exposure of low alkalinity surface waters to deposition of acidifying species over many years.

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[2] These criteria are conventionally used, as described, for example, by the USEPA. Water quality data were obtained from the Utah Division of Wildlife Resources and the Dept. of Environmental Health. Data for soils and bedrock geology were obtained from the U.S. Geological Survey.

[3] For this Assessment, the NO an NO2 mixture emitted by the IGS is assumed to be converted immediately to NO2 in the air.

We note that little information is available about baseline ambient air concentrations of NO_2 in Utah. A nonurban level considered typical of the IGS site area is about 4 to 6 ug/m^3. Maximum values in urban areas of the State range from 38 ug/m^3 to 60 ug/m^3.[4] Calculations indicate that the maximum annual average ground-level concentration of NO_2 due to the IGS would be 4.3 ug/m^3, 7 km from the plant.[5]

Atmospheric dilution would reduce the impact of IGS NO_x emissions substantially by the time they could be transported to the sensitive areas of the Wasatch Range some 160 km (100 miles) away. Assuming uniform vertical mixing and an average (neutral) stability condition, we estimate conservatively that the dilution in IGS emissions over this travel distance would be such that the annual or seasonal average contribution to the ambient NO_2 levels could be no more than about 6 percent of the maximum values near the plant site, i.e., about 0.3 ug/m^3. An 0.3 ug/m^3 contribution is less than 0.8 percent of the maximum annual ambient NO_2 levels in the sensitive areas of the Wasatch Range. As noted in the following section, terrain channeling of winds near the surface would normally preclude transport of IGS emissions into the high mountains of the Wasatch Range. Thus, even the insignificant estimate of 0.3 ug/m^3 increase is probably an overstatement of potential average IGS impacts in this area.

2.2 Transport of Pollutants From the IGS to Sensitive Areas

An important factor in evaluating the potential for significant impacts of a source to conditions at a receptor is

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[4]Bowers, J.F. Personal communication.

[5]Bowers, J.F., A.J. Anderson and W. R. Hargraves 1983. Calculated Air Quality Impact of Emissions from the Intermountain Generating Station -- Two Unit Configuration. Report TR-83-478-01. H.E. Cramer Co., Inc. Salt Lake City, UT.

the frequency with which the source's emissions may be transported toward the receptor by the winds. Several factors significantly limit the likelihood of transport from the IGS toward the potentially susceptible high elevation lakes in the Wasatch and Uinta Mountains.

The surface waters in Utah that exhibit low alkalinities, i.e., low acid-buffering capacity, are generally at elevations of 10,000 feet or more. Vertical mixing in the atmosphere over the Salt Lake Valley is normally restricted in winter to the lowest 3,000 feet by the presence of elevated inversions. The capping effect of the inversions effectively suppresses air motions that would cause pollutants in the valley to be carried into the high mountain areas to the east. Instead, the winds tend to flow from the south to southwest, i.e., parallel to the high terrain, although secondary upslope and downslope flow complicate the prevailing motions near the mountains. Thus, pollutants emitted by the IGS are transported mainly northward and parallel to the Wasatch Range, not eastward into the mountains. The extent to which polluted air from the source regions in the valley penetrates eastward into the areas considered susceptible to acidic deposition is unknown. However, circumstantial evidence that eastward transport is suppressed is found in Utah snowpack chemistry data. Messer et al.[6] found that chloride concentrations in snow were largely the result of atmospheric scavenging around the Salt Lake area. The water of Great Salt Lake has a substantial salt (NaCl) component. The data of Messer et al.[6] show that the chloride ion concentration in the snowpack decreases by a factor of two within an eastward distance of 30 miles from Salt Lake City. This strong change eastward into the mountains suggests that the rate of pollutant depositions

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[6] Messer, J., L. Slezak and C. Liff 1982. Potential for Acid Snowmelt in the Wasatch Mountains. Report UWRL/Q-82/06 Utah Water Research Laboratory, Utah State University, Logan, UT.

decreases rapidly as storms pass over the valley eastward into the mountains. The data is also consistent with the conclusion that the principal route of air transport in the valley parallels the mountains, and does not penetrate into areas to the east.

Nitrate ion data in the Wasatch Mountain snowpack does not show strong gradients like chloride. The reason for this difference is not known, but may be related to differences in cloud or precipitation scavenging of partially soluble NO_x gases <u>vs</u> scavenging of highly soluble NaCl particles. In any case, the concentrations of nitrate found in the snowpack east of Salt Lake City are 9.3 ueq/liter or less, as compared with larger precipitation values of 10 to 33 ueq/liter further east in Colorado.[7] This difference is important because it indicates the minimal influence of the Salt Lake City metropolitan area on depostion in the neighboring area. If the <u>local</u> Salt Lake City influence is small, then one would certainly not expect the IGS, 100 miles away, to have any appreciable effect in the sensitive mountain areas.

2.3 Lack of Evidence of Acidity Effects

The watersheds and biome of the Wasatch Mountains have been potentially exposed to elevated NO_x concentrations from the Salt Lake City and Provo metropolitan areas for many years. These exposures are much larger than the small incremental increase expected from the IGS plume. Is there any evidence of surface water acidification or of adverse effects from nitrate deposition in the mountains? Without exception the answer to this question is no.

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[7] Based on 1979-1980 observations from the Nation Acid Deposition Program (NADP) for sites in the Rocky Mountains of Colorado.

The work of Messer et al.[6] indicates that there is an abundance of alkalinity retained in the Wasatch snowpack and a lack of mineral acidity, both resulting from scavenged soil dust in the snow. This result essentially supercedes the result found in snow chemistry data for sites in the Wasatch Mountains 23

years earlier based on a very limited number of samples for Utah Mountain sites in 1959.[8] Two Wasatch Mountain samples showed (nitrite and nitrate) levels in snow to be between 1.7 and 11 ueq/liter. These are comparable to values reported by Messer et al.[6] for snow sampled in 1982.

Water quality data are available from historical lake surveys in the Uinta River, Provo River, Duchesne and Weber River watersheds from 1956 to 1981. Although the lakes sampled by the various surveys are rarely the same, the reported chemical properties show lake alkalinities in the mountains are generally 20 mg/liter as bicarbonate less. The pH value of these lakes range between 6.4 and 8.5 over this same time period.[9]

Data reported for six lakes surveyed in the Uinta Mountains showed nitrate levels of 0.05-0.10 mg/liter with pH 6.5-7.0 in 1956. A survey 23-25 years later of (different) Uinta Mountains lakes (1979-1981) showed nitrate levels from <0.05 to 0.2

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[8] Feth, J., S. Rogers, and C. Roberson 1964. Chemical Composition of Snow in the Northern Sierra Nevada and Other Areas. Water Supply Paper 1535-J. U.S. Geological Survey, U.S. Gov't Printing Office, Washington, DC.

[9] Reports of the Utah Div. of Wildlife Resources for the Lake Fork and Uinta River drainages (1971); Hales, D.C.D, 1958. An Inventory of the Waters of the High Uintas; Utah Dept. of Health 1982. State of Utah Clean Lakes Inventory and Classification. Utah Dept. of Health 1980. State Water Quality of Selected Impoundments.

mg/liter and field pH values between 5.8 and 8.2. One case, Pyramid Lake in 1981, was reported to have nitrate levels of 0.6 mg/liter and a pH value of 7.8. This comparison indicates no evidence of any historical change, either in pH or nitrate levels, in high altitude lakes of the Uinta Mountains. Unfortunately, no parallel information on historical trends appears to be available for the Wasatch Mountain waters. In the absence of such data, the Uinta history must be taken as a regional index of water quality.

As a final comment, it is noted that fish surveys have been conducted in the Uinta and Lake Fork River drainages. The surveys have been made by the Utah Division of Wildlife Resources since 1960. The surveys show no reports of fish population declines attributed to any water quality factor, including acidity.

2.4 Innocuous Nature of Nitrate Deposition

The effects of small incremental increases in nitrate deposition on the biome will be negligible because of its innocuous character. Nitrate is widely used as a fertilizer for enhancement of nitrogen-lean biosystems. It is rapidly assimilated into the biome as part of the growth and decay cycle. There is no evidence that nitrate <u>per se</u> acts in any way other than as a nutrient in terrestrial systems.

Nitrate is not retained in low-alkalinity mountain lakes or streams, because these waters are oligotrophic in character, and the biome is nutrient-lean. Added nitrate is taken up by both aquatic and terrestrial biota as a nutrient. Thus, we would not expect to see accumulation of nitrate in the low alkalinity lakes.

Nitrate deposition may also involve deposition of hydrogen ion. Some researchers have stated that increased acidity of snowpack results from nitric acid accumulation. As noted above, no reports of fish kills involving acidificaiton with snowmelt have been reported in the West. There is no precedent to expect that any small, incremental change in the deposition of nitrate (as an acid) on snow will cause damage to fisheries in the high altitude waters of the Wasatch Range.

3. SUMMARY OF CONCLUSIONS

A survey of available information indicates that the combination of atmoshperic dilution, terrain channeling of transport winds, and suppression of vertical mixing above the surface layer strongly reduces the possibility for any influence of NO_x emmisions from the proposed IGS on acid deposition in the neighboring, susceptible areas of the Wasatch Mountains.

The projected increase in annual ambient NO_2 concentrations due to IGS emissions are small (less than 0.8 percent) compared with current baseline urban levels measured in the State. No evidence exists in snowpack, precipitation or water quality data that suggests historical changes have occurred in acidity or in nitrate concentrations since the mid-1950s. This is despite the pressure of a growing metropolitan area around Salt Lake City and Provo, which has involved increased NO_x emissions from stationary and mobile sources since the 1950's.

H. E. Cramer company, inc.
POST OFFICE BOX 8049 • SALT LAKE CITY, UTAH 84108 • (801) 581-0220
UNIVERSITY OF UTAH RESEARCH PARK

1 July 1983

Mr. James H. Anthony
Project Director
Intermountain Power Project
P. O. Box 111, Room 931
Los Angeles, CA 90051

Subject: Response to Comments by the Utah Chapter Sierra Club, et al. on NO_x Emissions from the Intermountain Generating Station (IGS)

Dear Jim:

As requested by your staff, I have reviewed the following documents: (1) "Intermountain Power Project and NO_x Controls" by Howard Wilkerson, from the June-July 1983 issue of Uinta News (a publication of the Utah Chapter Sierra Club), and (2) the 20 April 1983 letter from the Utah Chapter Sierra Club, five other environmental organizations and one individual to the Utah Air Conservation Committee entitled "Intermountain Power Project and Selective Catalytic Reduction Technology." Among the major issues identified in one or both of the documents are the contentions that: (1) no dispersion model calculations of the air quality impact of emissions of oxides of nitrogen (NO_x) have ever been performed for the Intermountain Generating Station (IGS), (2) stationary source NO_x emissions in the State of Utah will be doubled by the addition of the NO_x emissions from the two-unit IGS as currently designed, (3) the NO_x emissions from the IGS will contribute to the current problem of non-attainment with some of the National Ambient Air Quality Standards (NAAQS) along the Wasatch Front, and (4) the NO_x emissions from the IGS will form a visible brown plume that will extend 20 miles or more downwind, depending on the meteorological conditions, in an area of high visibility. My comments on these four issues are given below. I point out that my comments are restricted to my areas of expertise and do not address issues such as the feasibility of various types of emission control technologies.

Issue (1)

All of the H. E. Cramer Company's dispersion model analyses of the air quality impact of emissions from the IGS (identified as the IPP Power Plant in our earliest reports) have included calculations of nitrogen dioxide (NO_2) concentrations (Bowers, et al., 1978a; Bowers, et al., 1981; and Bowers, et al., 1983). For example, under the assumption that all NO_x molecules are immediately converted to NO_2 as they exit the stack, Figure 3-2 of our report on the current two-unit version of the IGS (Bowers, et al., 1983) shows that the calculated maximum annual average ground-level NO_2 concentration attributable to emissions from the IGS of 4.3 micrograms per cubic meter occurs 7.1 kilometers north-northeast of the IGS stack. This maximum annual NO_2 concentration is a small fraction of the primary and secondary annual NAAQS for NO_2 of 100 micrograms per cubic meter.

Based on the air quality data available from the Utah Bureau of Air Quality (UBAQ), the highest annual NO_2 concentrations in the State of Utah of about 60 micrograms per cubic meter are found in the Wasatch Front cities of Provo and Salt Lake. These concentrations are primarily attributable to emissions from mobile sources along the Wasatch Front. In our air quality impact analysis for the original four-unit version of the IGS (Bowers, et al., 1978a), we concluded that there will be negligible interactions of emissions from the IGS with emissions from the mobile and stationary sources along the Wasatch Front because the IGS and the Wasatch Front are contained in different functional air basins. In other words, it is our opinion that it will be impossible to measure the effects of NO_x emissions from the IGS in the Wasatch Front area because the NO_x concentrations attributable to emissions from the IGS will be negligible.

Issue (2)

According to the article by Mr. Wilkerson, NO_x emissions from the current two-unit IGS "will approximately double the stationary source (as opposed to mobile sources such as cars) of NO_x emissions in Utah." To the best of our knowledge, this statement is based on erroneous or out-of-date information. According to the information provided to the H. E. Cramer Company for use in the air quality impact assessment that is contained in the Final Environmental Impact Statement for the expansion of the Emery (Hunter) Power Plant (Bowers, et al., 1978b), current NO_x emissions from only Hunter Units 1, 2 and 3 in combination with current NO_x emissions from Units 1 and 2 of the nearby Huntington Canyon Power Plant exceed the NO_x emissions that will result from the operation of the two-unit IGS by a factor of about 1.3. There are, of course, stationary sources of NO_x emissions in the State of Utah in addition to the Hunter and Huntington Canyon Power Plants. Thus, the NO_x emissions from the two-unit IGS will not double the stationary source NO_x emissions in Utah.

Issue (3)

We expect that NO_x emissions from the IGS will have the same negligible impact on the air quality in the Wasatch Front area as the impact of the NO_x emissions from the Hunter and Huntington Canyon Power Plants. Based on our examination of the NO_2 air quality data tabulated by the UBAQ for the Wasatch Front cities of Provo and Salt Lake, we are unable to discern any effects of the increases in stationary source NO_x emissions as Hunter Units 1, 2 and 3 and the second Huntington unit (Unit 1) came on line during the late 1970's and early 1980's. For example, the annual average NO_2 concentrations in Salt Lake City and Provo were constant during the period 1979 through 1982. To illustrate that the effects on NO_2 air quality in the Wasatch Front area of emissions from these two power plants are negligible in comparison with the effects of emissions from local mobile and stationary sources and the effects of year-to-year variations in meteorological conditions, the highest and second-highest hourly NO_2 concentrations measured in Provo and Salt Lake City during 1981 were lower than during 1980.

The letter from the Sierra Club, et al. expresses a concern about the fact that the Wasatch Front area currently is not attaining some of the NAAQS (40 CFR 52.2331). However, we point out that the entire State of Utah is an attainment area for the NO_2 NAAQS. Even if the maximum ground-level NO_2 concentration estimated at any point for emissions from the two-unit IGS is added to the maximum NO_2 concentration measured in the State of Utah, the resulting concentration is well below the NAAQS. Additionally, because of the negligible NO_x concentrations that we expect along the Wasatch Front as a result of emissions from the IGS, we expect that emissions from the IGS will produce negligible contributions to the concentrations in the Wasatch Front area of photochemical air pollutants such as ozone (O_3).

Issue (4)

Mr. Wilkerson's article concludes that, "Finally, the NO_x will be visible, depending on the weather, as a brown plume twenty or more miles long in a region which now has high visibility." Based on the available data, the Delta area does not have "high visibility" in comparison with the pristine air quality areas of Utah. The mean visual range (maximum distance at which an object can be seen) at the Delta, Utah Airport during the period 1949 through 1954 (the most recent period for which visibility observations are available) was only about 70 kilometers (Bowers, 1979). This visibility is much less than the 170-kilometer regional visual range estimated for Utah by Latimer and Ireson (1980, Figure 13). Our analysis of the Delta Airport hourly surface weather observations indicated that wind-blown dust, probably attributable to agricultural activities, was the primary cause of the relatively poor visibility in the Delta area.

Whether the plume from the IGS will be visible will depend on the background illumination, the plume constituents and dimensions, and the relative position of the sun, plume and observer. The brown plume described in Mr. Wilkerson's article assumes that the NO_2 concentration in the IGS plume is sufficiently high that enough blue light is selectively absorbed to produce a discernible discoloration. Although we have not evaluated the potential visibility impacts of emissions from the IGS within 20 miles of the IGS plant site, we have evaluated the visibility impacts at the nearest existing and potential Class I (pristine air quality) areas of emissions from the original four-unit IGS configuration (Bowers, 1979). The results of our model calculations indicated that there will be no detectable atmospheric discolorations or reductions in the visual range attributable to these emissions.

I hope that the above comments help to place in perspective the concerns expressed in Mr. Wilkerson's article and in the Sierra Club, et al. letter.

Sincerely,

James F. Bowers

James F. Bowers
Principal Scientist

JFB:bjs/aj

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ATTACHMENT 4

STUDY FOR PARTICULATE CONTROL EQUIPMENT
ELECTROSTATIC PRECIPITATORS AND FABRIC FILTERS
INTERMOUNTAIN POWER PROJECT

Task No. PAA66

Prepared by

HUNG BEN CHU

Approved by:

Henry S. Sanenstom 9/12/80
Air Quality Systems

Henry T. Dziesiel
Special Projects & Planning Subsection

L. G. Weidner
Engineer of Mechanical Design

Mechanical Design Section
Design and Construction Division
Los Angeles Department of Water and Power

April 30, 1980

EXECUTIVE SUMMARY

The objective of this study is to compare electrostatic precipitators and fabric filters applied to the Intermountain Power Project (IPP) as the particulate collection device.

After thoroughly examining the advantages and disadvantages of these two particulate control equipment alternatives, the selection of fabric filter is recommended. Major reasons for this recommendation are summarized as follows:

1. The performance of electrostatic precipitators depends very much on coal and fly ash properties, but this is not usually true for fabric filters. IPP has not obtained confirmed sources of coal supply and, furthermore, it is almost impossible to secure consistently uniform coal properties during the life of the plant. The uncertainty of coal properties makes the fabric filter a better choice than the precipitator.

2. In general, fabric filters have higher collecting efficiencies than electrostatic precipitators and, moreover, they can consistently maintain this high efficiency. A well designed precipitator can achieve very high efficiency, but this efficiency tends to vary, depending on coal properties and operating conditions. Field experiences have shown that precipitators often gradually deteriorate after a few weeks of operation and have to be shut down for washing and other maintenance to maintain high efficiency.

3. Fabric filters are more effective in reducing plume opacity than electrostatic precipitators. The major contributions for visible plumes are fine particles in the size range of 0.2 to 1.0 micron. Fabric filters can collect these fine particles more effectively than precipitators can. Plume opacity is an important consideration for selecting particulates control device because IPP is located in an area where aesthetics is a very sensitive issue.

4. Cost comparisons show that the fabric filter is less expensive than the precipitator. The fabric filter also has the potential to further reduce its costs by increasing bag life.

5. In the western states where low-sulfur coals are the major source of fuel, more utilities have committed themselves to fabric filters than those committed to precipitators. It appears that the performance record of fabric filters has already convinced electric utilities of their superiority over precipitators.

In this study, the favorable results for fabric filters make the recommendation obvious. But it should be noted that the conclusions are only applicable to generating stations burning low-sulfur coals and under certain conditions. It is not the intention of this study to generalize the results for all cases.

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I. Introduction

The purpose of this report is to provide technical and economic evaluations of the alternative methods of particulate emission control for the Intermountain Power Project (IPP) Generating Station located in the Delta-Lynndyl area of Central Utah.

A key environmental problem facing the electric utility industry is the increased emphasis by regulatory agencies on the application of high efficiency particulate control devices to pulverized coal-fired boilers. The particulate emission limit initially set by the Environmental Protection Agency (EPA) was 0.1 $lb/10^6$ Btu. Under the Clean Air Act of 1977, EPA promulgated on June 11, 1979, a New Source Performance Standard for particulates of 0.03 $lb/10^6$ Btu, which is more than three times stricter than the previous limit. In the Conditional Permit to Commence Construction and Operation of IPP by EPA Region VIII, the particulate emissions are further limited to only 0.02 $lb/10^6$ Btu. This stringent particulate emission limit has a definite impact on the selection of particulate control equipment.

Electrostatic precipitators have been the dominant particulate collection device in the electric utility industry for many years. However, increasingly stringent emission standards have led to substantially higher costs for precipitators. These costs have increased so high that fabric filters (baghouses) have become a competitive alternative in achieving cost effective control of particulate emissions.

Besides cost considerations, the stringent emission limits also have placed fabric filters in a technically favorable position, based on data from increasing numbers of recent fabric filter applications to utility boilers.

This report compares the advantages and disadvantages of fabric filters and precipitators in light of such factors as coal properties, visibility, availability, other utilities' experiences, costs and related regulations. A final recommendation is made based on these comparisons.

II. Technical Discussion

A. Electrostatic Precipitator

Precipitators have operated successfully over a number of years for a wide range of particle sizes for the electric utilities. The basic precipitation process takes place in three steps: first, the particles in the flue gas are charged by bombardment of gaseous ions that are produced by means of a high voltage corona discharge. The charged particles then migrate to a collecting electrode of opposite polarity; and finally, the collected material is disloged by mechanical forces to an appropriate storage space for subsequent disposal.

1. The Performance of Precipitators

The performance of a precipitator is sensitive to a number of items, which are sometimes interrelated with each other. A brief discussion of them is given here:

a. Coal Characteristics

The performance of an electrostatic precipitator is affected throughout its operating life by the coal burned in the boiler. A major coal characteristic of concern is its fly ash resistivity. The resistivity is a function of 1) flue gas temperature, 2) fly ash mineral analysis, 3) flue gas moisture, and 4) sulfur content in the coal. Western low-sulfur coals are noted for their high resistivity ash and difficulty to precipitate. Figure 1 presents typical curves of electrical resistivity as a function of flue gas temperature and sulfur content in the coal.(1) To overcome the difficulties of high resistivity fly ash, three methods are generally employed:

1) to oversize the precipitator, 2) to inject gas conditioning chemicals, 3) to use the precipitator before the air preheater (hot-side precipitator). But any one of these has its own problems to be solved.

Sodium content in the coal also affects the performance of precipitators; the coal with low sodium content produces unsatisfactory precipitator performance. Field operating data shows that a reduction in sodium content from three percent to one percent produces almost a 50 percent decrease in effective migration velocity. A 50 percent decrease in migration velocity requires approximately a 50 percent increase in required precipitator size. This approximation can be found from the Deutsch equation which is the basis for precipitator design.

Precipitator specifications should be based on coal properties. The more coal information one can obtain prior to issuing the precipitator specification, the less chance there will be of a performance problem. Thought should also be given to coal properties which may be encountered many years into the future. Coal core sample analysis should be required from areas of mines which will be mined many years into the future.

b. Specific Collection Area

Specific Collection Area (SCA) is defined as the area of collection surface per 1000 actual cubic feet per minute of flue gas flow. The commonly used unit is $ft^2/1000$ acfm, which generally describes the size of a precipitator. SCA is dependent on required collection efficiency, particle size distribution, ash chemical properties, altitude, and others.

The use of electrostatic precipitators to collect 90 percent or more of the fly ash at coal burning power plants has been commonplace for 50 years. At the collecting efficiency of 90 percent, precipitators can perform very well using SCA well under 200. In recent years, however, more and more stringent particulate emission standards push the collecting efficiency to 99 or 99.5 percent for new coal-fired power plants in the United States. This requires a precipitator with much larger SCA. For example, a precipitator for 99 percent efficiency is at least twice as big (and costly) as one for 90 percent efficiency, for any given type of fly ash from a given flue gas composition at a given temperature and humidity.

To achieve adequate performance, the trend for precipitator design is that a much larger SCA is used for new power plants than for the existing ones. For example, under the New Source Performance Standard of 0.03 lb per million Btu, EPA has predicted 1000 SCA for low-sulfur western coal.[2] The larger size precipitator of course affects the capital as well as operating costs.

c. Flue Gas Flow Distribution

Poor gas flow distribution can seriously impair the performance of a precipitator. This poor distribution results from poor inlet duct arrangement or from fluctuations in boiler load. With gas flow at a high velocity through some parts of the system and at a low velocity through other parts, the overall collection efficiency is reduced. This reduction is caused by the effect of creating different specific collection areas across the face of the precipitator. High velocity areas have the effect of reducing the precipitator collection surface per unit of gas flow.

d. Boiler Operating Conditions

Boiler operating conditions can have a dramatic effect on a precipitator's performance. Flue gas flow may vary due to variations in the coal properties. There may be periods when operation with increased boiler excess air is required. The leakage of air preheaters will increase with time. All these operating conditions will affect the performance of a precipitator.

Sometimes oxygen imbalances occur across the boiler. The imbalance forces the operator to boost the total air flow in order to operate with a safe oxygen level in all areas of the boiler. This increase of air flow can usually affect the precipitator's performance. Also variation in temperature across the flue gas can result in significant differences in temperature across the precipitator which in turn influences precipitator performance.

2. Cold and Hot precipitators

Precipitators are classified as cold side units when they have been installed downstream of the air preheater where gas temperatures are in the range of 250 deg F to 350 deg F. Hot precipitators are those installed upstream of the air preheater where gas temperatures are in 650 deg F to 750 deg F range.

Cold precipitators have been used for many years in the utility industry burning high-sulfur coals. As the result of more stringent rules on SO_2 emissions, utilities started to consume more low-sulfur coals for power generation. High ash resistivity is always associated with low-sulfur coal which results in lower collection efficiency. Since ash resistivity can be reduced by increasing gas temperature, the hot precipitator was introduced for units burning low-sulfur coal.

A hot precipitator treats a larger flue gas volume because of the elevated temperature. Besides, other problems, such as air leakage and differential thermal expansion between different parts, cause operating difficulties.

In the past few years, the discussion to install hot or cold precipitator has always been controversial. Vendors have taken opposing sides of the argument. For low-sulfur coal, the size of a cold precipitator can be enlarged to achieve the same collection efficiency as a hot precipitator. It seems that with proper attention to design consideration and good operating and maintenance practices, both can be competitive alternatives.

3. American and European Designed Precipitators

American designed precipitators use a weighted wire for the discharge electrode and a light gauge flat plate for the collecting electrode. They utilize rapping forces of 10 to 50 g's (10 to 50 times of the acceleration of gravity) to drive the dust into the hoppers. The light weight construction does not allow very high intensity rapping, which is required for the high resistivity ashes. The basic advantage of this design is the relatively low capital cost.

The main features of a European designed precipitator are: 1) the discharge electrode is supported with a rigid frame to reduce wire breakage, 2) the rapping intensity is at least 100 g's, (100 times the acceleration of gravity). The European design is usually stronger and larger than the American design. The European design costs more but is more capable of handling high resistivity fly ash and maintaining performance efficiency.

B. Fabric Filter

The basic design of a fabric filter unit is simple and straightforward. It employs the filtering capability of high-efficiency woven or felted fabric to form tubes or bags that are placed in a housing structure called a baghouse. (In this report, the baghouse and the fabric filter are meant to be the same equipment and are used interchangeably.) The high efficiency requirements of particulate removal and longer bag life have made the application of the baghouse economically competitive with electrostatic precipitators.

When flue gases pass through the cloth filter, particulates are trapped in the fabric mesh. The collection process is enhanced by the particulate cake that is built up on the fabric surface. This particulate cake acts as a filter to the finer particles in the flue gas stream. As this "filter cake" increases in thickness, the pressure drop across the filter surface increases. In order to avoid an excessively high pressure drop across the bag surface, the filter bags are periodically cleaned to remove most of the built-up filter cake. The filter cake then falls into an ash collection hopper beneath the filter bags for eventual removal.

1. The Performance of Fabric Filters

Fabric filter units are not sensitive to fly ash resistivity and have proven themselves capable of high particulate removal efficiencies to produce very low outlet dust loadings. To use western low-sulfur coal under existing stringent emissions regulations, these two factors put baghouses on a favorable or at least competitive position to precipitators.

Major limitations to the successful performance of baghouses are flue gas temperature and pressure drop. Temperature is limited to about 550 deg F at the high end to prevent bag damages. At the lower end of the temperature scale, temperatures are limited to about 30 deg F above the water dew point to prevent bag plugging by condensed moisture. During boiler start-up, the flue gas is bypassed from the baghouse to avoid bag damages. In addition to the bypass, the baghouse sometimes is heated to reach the temperature above the dew point before being put back on line. Pressure drop across bags depends on the gas volume filtered through a unit area of cloth which is called the air-to-cloth ratio. Too high an air-to-cloth ratio leads to increased filter resistance, and hence, high pressure drop. This high pressure drop causes excessive bag wear and reduces bag life. It may also cause load reductions due to fan power limitations.

Baghouse configuration also has a significant effect on baghouse performance. Multi-cell construction is necessary for good performance. The general approach is that two cells can be taken off-line at full load, one undergoing cleaning process and one undergoing maintenance. With this design, even the largest steam generator can be operated with limited downtime for repair or maintenance, thus enhancing the availability of the particulate control system. When the boiler is operated at low loads, it is often necessary to shut off part of the baghouse cells to keep gas temperature high enough to prevent moisture condensation.

2. Fabric Filter Sizing

Basically, a fabric filter is a device producing a relatively constant outlet grain loading even with various ash contents in the coal. Thus, the required particulate removal efficiency has little impact on the size of the baghouse.

The most significant factor in determining baghouse size is the air-to-cloth ratio (A/C ratio). Also the size of the individual bags (diameter and length of the bag) will affect the baghouse size. In order to limit the pressure drop to under five inches water, the A/C ratio of two is considered to be a conservative criteria for sizing a baghouse for a coal-fired power plant.(3)

3. Cleaning Mechanism

All baghouses operate in basically the same way, and the main variations between different baghouses are in the type of fabric used and the fabric cleaning mechanism. In fact, it is the cleaning method that characterizes one type of baghouse from another.

Filter bags are cleaned by three basic methods. These include shaking, reverse gas flow, and pulse jet. Sometimes more than one of the cleaning methods are used in combination or the baghouse is designed so that the operator can select operation in either a single cleaning mode or in a combination of cleaning modes. It is generally believed that reverse gas flow is the best method of cleaning because it does not subject the fabric to severe stress as the case with shaking or pulse jet.

a. Shaking

The shaking method cleans the bags in a manner similar to shaking a rug. Before the shaking starts, dirty gas flow is shut off in a single compartment. The bags in this compartment are then shaken at the top to dislodge the dust which is then collected in the hopper below. The shaking mechanism design must be especially adapted to the type of fabric used. Shaking is a vigorous cleaning method and can be accomplished in various degrees of severity. Too violent shaking can damage the bags. Too gentle shaking may fail to dislodge deeply embedded fly ash. Consequently, controls are needed to permit adjustment of the intensity, frequency and duration of shaking.

b. Reverse Gas Flow

With reverse gas cleaning, the clean gas outlet of a cell is shut off first. Following a brief no flow period for dust settling, clean flue gas is introduced in a reverse flow to gently collapse a part of the bags and dislodge the ash, allowing it to fall into the hoppers. Following another quiescent no-flow period, the cell is returned to service. Typical cleaning processes are usually so designed that compartments (or cells) are continuously cleaned on a cyclic basis, one at a time. The period between cleaning cycles can be adjusted to accommodate various inlet grain loadings produced by different coal ash contents. Proper control of the frequency of cleaning and duration of cleaning will maintain an acceptable pressure drop across the entire baghouse. Normally, baghouses with this cleaning method and the shaking method are compartmentalized so that one compartment can be isolated for cleaning, while the remaining compartments handle the total gas flow.

c. Pulse Jet

With pulse jet cleaning, each individual bag is subjected to a high intensity blast of air from inside of the bag. The pulse action expands the bag and forces the dust cake from the exterior side of the bag. A venturi of diffuser nozzle is usually mounted on the top of the bag and assists the pulse jet by aspirating secondary air. Pulse jet units are usually designed so that pulse time, the interval between pulses, the number of pulses, and the frequency of cleaning can be adjusted.

The cleaning can be accomplished either while the bag is filtering combustion gases or with the compartment off-line.

4. Pressure Drop

Pressure drop through the fabric filter system is one of the major concerns to the potential user. Most baghouse systems are designed for a flange-to-flange pressure loss of four to eight inches water. Many factors affect pressure drop in the baghouse, such as A/C ratio, inlet grain loading, frequency of cleaning, duration of cleaning, and the number of compartments. The dominating factor is the A/C ratio. By averaging data from different sources, R. M. Jensen[4] of Bechtel Power Corporation derived an equation relating pressure drop and A/C ratio as below:

$$\Delta P = 0.566V^{1.8}$$

Where ΔP is the pressure drop in inches of water column and V is A/C ratio in feet per minute. Figure 2 presents the relation between pressure drop and A/C ratio. It should be noted that the curve in Figure 2 is only an average value and cannot be used for design purposes; but the relationship is very clearly demonstrated.

With properly designed A/C ratio, the pressure drop can be limited by the frequency and duration of cleaning. Two different controls can be employed to limit pressure drop, timing controls or pressure controls. With timing controls, the compartments of a baghouse are cleaned at predetermined intervals which keep the pressure drop below certain values. With pressure control, a predetermined cleaning cycle is initiated each time the pressure drop across the baghouse exceeds certain values.

5. Baglife and Bag Material

The fabric filter baglife is a function of many variables such as operating A/C ratio, pressure drop, cleaning method and its intensity and frequency, chemical properties of fly ash, particulate loading and particulate size distribution. Vendors usually guarantee two-year bag life, but based on actual field experience, bag life of three or more years can be expected.

Selection of bag material is one of the most important factors in prolonging bag life. The choice of fabric is dependent upon the inlet gas temperature, particulate chemical characteristics, particle size and concentration, acid dew point temperature, and moisture content of the gas stream. To withstand the operating temperatures and sulfur oxide content from coal-fired boilers, the only commercially proven fabrics are woven fiberglass and felted teflon according to E. W. Stenby of Stearns-Roger Inc.(5)

6. Design Considerations

Important considerations in designing baghouses for coal-fired utility boilers are listed as below:

a. Use conservative air-to-cloth ratio. The gross A/C ratio should be about 2 to 1. With one or two compartments out for cleaning and maintenance, the ratio can be higher, but never exceeding 2.5 to 1. With proper cleaning methods, the 2 to 1 ratio is consistent with acceptable pressure drop, long bag life and good particulate collection efficiency.

b. Design pressure drop should be a nominal four inches water with maximum of six inches water. Based on field testing data, the Environmental Protection Agency (EPA) reported that using an air-to-cloth ratio of 2 to 1, a pressure drop of five inches water or less can be achieved.

c. Use reverse air cleaning method.(3) This is the most gentle method for filter bag cleaning. The cleaning cycle should be automatically controlled by monitoring baghouse pressure drop. Once the pressure drop reaches a present limit, the cleaning cycle should be started. A timed cleaning cycle should also be provided.

d. The baghouse should be designed to operate at full load with two compartments off-line, one for cleaning and one for maintenance. This arrangement will increase the baghouse reliability and availability.

e. Provide low gas inlet velocity to each compartment with sufficient ash hopper storage capacity to minimize turbulence and reentrainment of fly ash.

f. Monitor and control flue gas temperature at baghouse inlet to stay at least 30 deg F above the water dew point. An air heater bypass should be provided for increasing flue gas temperature when the boiler is operated at low loads.

g. Woven fiberglass with teflon coating should be considered as bag material. Field testing indicated that this type of bag material can achieve very high particulate removal efficiency.(6)

h. Easy and safe bag replacement arrangement should be provided.

i. Opacity and pressure drop monitoring instruments should be installed to detect failures as early as possbile.

j. Provide proper bag tensioning to achieve good performance and extended bag life.

k. The heating of baghouses and hoppers may be necessary under extremly cold weather.

III. Cost Estimates

Costs of electrostatic precipitators and fabric filters are compared and discussed in this section from three different sources. The first one was reported by EPA for their background information.(3) The second source was developed by Stearns-Roger Engineering Corporation and Electric Power Research Institute.(7) The third one came from a study for IPP by GCA Corporation.(8) It should be noted that the purpose of these cost estimates is to give adequate comparisons between electrostatic precipitators and fabric filters on the same basis. These costs do not necessarily reflect actual capital and annualized costs because of different methods of calculations by different sources.

A. EPA Cost Estimates

To cover a realistic spread of conditions that might occur within the electric utility industry, EPA's estimates considered two types of coal, three different control systems and four plant sizes. The two types of coal were: one containing 0.8 percent sulfur, 8.0 percent ash, and a heat value of 10,000 Btu/lb; the other one containing 3.5 percent sulfur, 14 percent ash, and a heat value of 12,000 Btu/lb. Three control systems were fabric filter, electrostatic precipitator and venturi scrubber. The plant sizes were 25, 100, 500, and 1000 MW. For the application to IPP, only low-sulfur coal with fabric filter and electrostatic precipitator are considered here.

1. Capital Costs

Capital costs are in 1980 dollars which include indirect costs covering interest during construction, field overhead, engineering, freight, offsites, taxes, spares and start-up. These indirect costs are estimated as 33.75 percent of installed cost. Also, a contingency allowance of 20 percent of the total is added to reach the final turnkey investment.

For fabric filter, an air-to-cloth ratio of 2:1 is used for the estimates. For the electrostatic precipitator, three sizes of precipitators are used because the removal efficiency is a function of the plate area, and the cost is also a function of the plate area. The sizes vary from 400 to 650 square feet per 1000 acfm.

2. Annualized Costs

The total annualized costs include direct operating costs and annualized capital charge. Direct operating costs include fixed and variable annual costs such as: labor and materials needed to operate equipments, maintenance labor and materials, utilities including electric power, fuel, water and steam, and disposal of liquid and solid wastes. Annualized capital charges include capital recovery factors representing 10 percent interest over a 20-year life. An additional four percent of total investment was also added to cover general administration, property taxes, and insurance. The mills per kilowatt-hour were computed using a 65 percent operating factor.

Table 1 presents capital and annualized costs for both fabric filters and electrostatic precipitators. For a power plant of 820 MW such as for the IPP unit, the capital cost for a fabric filter is about $45 million, and the capital cost for an electrostatic precipitator is $62 million. The annualized costs are 1.86 mills/kWh for the fabric filter and 3.55 mills/kWh for the precipitator. These numbers were interpolated between 500 MW and 1000 MW. The economic advantage of fabric filter over precipitator is clearly shown here. A specific collection area (SCA) of 650 was chosen for the precipitator cost estimation, because for a stringent regulation of 0.02 lb/10^6 Btu emission rate, this is a more realistic number to be used.

B. Stearns-Roger Cost Estimates

The economic findings by Stearns-Roger was sponsored by the Electric Power Research Institute and presented in 1979. The cost estimates were based on a 500 MW pulverized coal-fired boiler burning four different types of coal. The coals were Wyoming subbituminous (0.56 percent sulfur), North Dakota lignite (0.68 percent sulfur), Alabama bituminous (1.9 percent sulfur) and Eastern bituminous. Since a Utah coal was not included in the study, the costs using Wyoming subbituminous coal are presented here, because the Wyoming coal is the most similar to the Utah coals that are expected to be used at IPP.

Five different particulate collection systems were considered: hot side precipitator, cold side precipitator, fabric filter with 20 compartments and two-year bag life, fabric filter with 20 compartments and four-year bag life, and fabric filter with 40 compartments and two-year bag life.

1. Capital Costs

Capital costs were estimated for a range of outlet emission levels. Included in the estimates are materials and labor for installation of the collectors, hoppers, support steel, ducts nozzles, dampers, fans, expansion joints, ash-handling equipment, insulation, and other miscellaneous items. Indirect costs and ten percent contingency allowance are also included in the cost estimation.

Figure 3 shows capital cost in 1980 dollars for several different particulate control systems. The costs were escalated from 1978 to 1980 using a 9.4 percent annual inflation rate. It is demonstrated in the figure that the capital cost for precipitators increases as the outlet emission is reduced. Since fabric filters operate at high particulate removal efficiencies with relatively constant outlet loading, the capital cost is essentially constant for the range of emission limits.

2. Annualized Costs

The annualized costs combine capital investment, operating and maintenance costs, and power requirements. For Stearns-Roger analysis, the following factors were used:

Minimum acceptable return	11%
Fixed charge rate (depreciation, insurance, etc.)	16%
Interest during construction	8.5%
Escalation (fuel, material and labor)	7%
Plant capacity factor	70%

Figure 4 gives annualized costs in mills/kWh as the function of particulate emission limits. The costs were also escalated from 1978 to 1980 using a 9.4 percent annual inflation rate.

Both capital cost and annualized cost are higher for electrostatic precipitator than for fabric filter as demonstrated in Figures 3 and 4. The differential cost is wider when lower particulate emission limit is approaching. The cost estimates are somewhat lower than those presented by EPA, because in the EPA model a more conservative method was used in its calculation. Nevertheless, the trend for the costs of fabric filters and precipitators are clearly demonstrated in both models.

C. GCA Cost Estimates

GCA Corporation, under a contract with the Department, made their cost estimates based on three different sources. The first source was derived from theoretical and existing plant data. The second source was based on cost models developed by the Department of Energy (DOE) and Research-Cottrell, Inc. (RC). The last one was cost information obtained by GCA from ten equipment manufacturers.

Both DOE and RC cost models were used to calculate capital costs and annualized costs for fabric filter and precipitator control systems for IPP. The costs from these two models can be used for comparison purposes but not for the representation of the actual equipment and operating costs. By comparing the results of the two models with vendor estimates, GCA suggested that a baghouse appeared to be the economical choice, when the precipitator's specific collection area exceeds 600. This comparison was based on fabric filter A/C ratio of two.

GCA suggested that vendor's cost information should be viewed as the most reliable and accurate since the various vendors responded directly to fuel and system specifications. Among the response received from the vendors, four quoted prices for a cold precipitator only, two quoted prices for a baghouse only, and four quoted prices for both control systems. All equipment were designed to achieve an outlet loading of 0.03 $lb/10^6$ Btu. Summaries of all cost estimates are presented in Table 2 with the ten vendors identified by letter code A through J.

1. Capital Costs

As presented in Table 2, the capital costs vary over a wide range. Installed costs for fabric filter ranged from \$12.6 millions to \$18.4 millions; those for precipitators are from \$13.5 millions to \$24 millions. Based on the capital cost, it appears that the fabric filter would be the economical choice compared to the electrostatic precipitator.

The costs suggested by vendors are much lower than those estimated by EPA or S-R. The major reason for the differences is that the installed costs did not include indirect costs and contingency allowances.

2. Annualized Costs

GCA calculated annualized costs based on data provided by Vendor H. for the following reasons:

- Vendor H's information is the most detailed.
- They appear to be unbiased because they have proposed both a baghouse and a precipitator.
- The vendor is a leader in the field of control equipment design and manufacture.
- The specific collection area is in the middle of the range quoted for all ESP equipment.
- The baghouse quoted is conservative in design with respect to A/C ratio and cleaning method.

The annualized costs are given in Tables 3 and 4 for the electrostatic precipitator and fabric filter, respectively. Both costs are a little over one mill/kWh. The cost can be shifted in favcr of fabric filter if bag life of more than two years is achieved.

IV. Comparisons between Electrostatic Precipitator and Fabric Filter

In order to have any meaningful comparison between electrostatic precipitator and fabric filter, two important factors must be considered.

1. The extremely stringent New Source Performance Standards for particulate emissions of 0.03 $lb/10^6$ Btu was promulgated by EPA on June 11, 1979. To make things worse, IPP has been committed to even less particulate emissions of 0.02 $lb/10^6$ Btu as indicated in the Conditional Permit to Commence Construction and Operation of IPP Generating Station.

2. Only low-sulfur western coal will be burned in the IPP boilers, and sources of coal supply have not been confirmed. A coal validation study is now in progress to identify coal sources for IPP. Prior to the completion of this report, the results of this study were not available.

In comparing these two particulate collection devices, considerations are given to coal properties, performance efficiencies, opacity, actual field experience, reliability, costs and others. Based on results of the comparisons, a recommendation for the selection of equipment was made.

A. Coal Properties

In order to properly evaluate particulate collection devices, one must know the coal properties for properly sizing the equipment. Of the coal analysis parameters, sulfur content, ash content and heating value are of greatest significance.

Recently, it has been found that sodium content is also an important factor to affect the collectibility of particulates for low-sulfur coal applications.

Currently, IPP has not obtained confirmed sources of coal supply. The best available data was a range of values for coal properties as presented in Table 5. A range of values does not provide an accurate assessment of the fuel characteristics.

Under today's high efficiency requirements, the electrostatic precipitator manufacturers need more and more accurate information of coal properties for proper precipitator sizing. To some precipitor manufacturers, specification of "average" or "broad range" coal and ash properties is becoming an unsatisfactory situation. Instead, a full presentation of all drilling core analyses or a statistical distribution analysis of the range is preferred. Without an adequate representation of coal samples, the design of an electrostatic precipitator to assure an extremely high removal efficiency is almost impossible.

Fabric filters have the advantage of insensitivity to coal and fly ash chemical characteristics. Electrical resistivity is not a consideration in fabric filter design. It is generally agreed that coal properties have only limited effect on fabric filter operations.

Since only a broad range of coal and ash properties can be provided, and future coal sources are uncertain during the life of the plant, fabric filter is the preferred choice of the two.

B. Particulates Collection Efficiency

Particulate collection efficiency of 99.5 percent and over is required under the very stringent emission limitation of 0.02 lb/10^6 Btu. Preliminary calculation, based on highest ash content in coals, shows that efficiency of at least 99.71 percent is required for the IPP units.

Although electrostatic precipitators are designed as constant efficiency devices, the efficiency usually varies with coal and ash properties, flue gas distribution, and temperature fluctuations. It has been experienced by the utilities that precipitators gradually deteriorated after a few weeks of operation, and the units have to be shut down for washing and other maintenance to maintain high efficiencies.

Of all the factors affecting the precipitator performance, fly ash resistivity is the most serious one. As shown in Figure 1, low-sulfur coals have much higher fly ash resistivity than high-sulfur coals. The high resistivity fly ash can lead to back corona and spark erosion within the precipitator, which may shorten component life and reduce collecting efficiency. Since fly ash resistivity is likely to change during the plant lifetime, which is expected from a new coal source, precipitator performance becomes uncertain. Under the strict particulate emission regulations, a small drop in efficiency would cause a violation of the law which could cause the plant to be shut down.

A survey was conducted by GCA[8] and also by the Department to investigate the performance of electrostatic precipitators. The results are presented in Table 6. With only a few exceptions, the survey shows that the performance test efficiencies generally do not meet the design efficiencies. These are only small samples, so it does not suggest any significant trend for precipitator failures. But, it does show the difficulty for precipitators to achieve design efficiency due to various problems.

Contrarily, properly designed fabric filters can meet very strict emission requirements, and its efficiency seldom varies. The ability to keep low emission rates is mainly due to its independence of coal and ash characteristics, fuel gas distribution and temperature fluctuations.

It can be generally concluded that fabric filters will be able to consistently maintain compliance of a very stringent rule on any low-sulfur coal the plant can burn, but electrostatic precipitators may not be able to maintain continuously high efficiencies because of the uncertainty of coal properties and various operating conditions. Thus, from the efficiency point of view, the fabric filter is a better choice.

C. Opacity and Fine Particles

Currently, the standard for opacity is limited to 20 percent over six minutes average time. This is a standard that is not difficult to comply with by fabric filters or a well-designed precipitator. Therefore, a clear stack should be achieved as much as possible.

Fine particles in the range between 0.2 to 1.0 micron are the major contributors for visible plume since fly ash of this size range is a very efficient light scatterer. Blue light is in the range of 0.4 to 0.5 micron wavelength. More particles of this size range will interfere with blue light, producing visible plume.

Besides the visibility problems, fine particles may also cause adverse health effects. Increasing concern over these potential health effects would presumably force emission limitation standards based on particulate size as well as total mass. For example, the State of New Mexico has already instituted a standard which limits emissions from utility steam generators to 0.05 lb per million Btu total particulates and also more stringent 0.02 lb per million Btu for particulates less than two micron diameter. Similar fine particulate standards are also under consideration by the Environmental Protection Agency.

Generally, higher opacity can be expected from precipitator emissions than from fabric filters because fabric filters are more effective in removing fine particulates in the size range of 0.2 to 1.0 micron, which are the material primarily responsible for opacity problems. Available data shows that collecting efficiency for an electrostatic precipitator is approximately proportional to particle diameter over a size range of 0.2 to 20 micron. A recent study on electrostatic precipitator performance for a large utility boiler burning low-sulfur coal found that collection efficiencies of 99.6, 98 and 90 percent were observed for particles having diameters of 20, 2 and 0.2 micron, respectively.[9] Similar findings were also reported elsewhere.[10] Figure 5 presents measured fractional efficiencies versus particle diameter for a cold-side precipitator burning low-sulfur coal. It clearly demonstrates the lower collection efficiency in the range of 0.2 to 1.0 micron which is the major cause of visible plumes.

To compare the collecting efficiencies for fine particulates between fabric filters and electrostatic precipitators, Table 7 gives, as an example, a proposed efficiency guarantee by a vendor.[11] The collection efficiency for fabric filter is constant at 99.8 percent and independent of particle sizes, but precipitator efficiencies vary from 95.19 percent for 0.3 micron particles to 99.93 percent for 10 micron particles. This difference of efficiencies can make a large difference in opacity from stack emissions.

D. Costs

In Section III, three sources of cost comparison have been presented. The comparisons covered those based on plant sizes, emission limitations and budgetary costs provided by manufacturers. Although those costs do not necessarily represent actual capital and annualized costs because of different methods of calculations, they do give adequate comparisons between electrostatic precipitators and fabric filters on the same basis. All three sources present the same conclusions: The fabric filter is a more economic choice than the precipitator under the current strict emissions limitation. In its background information, EPA has stated that fabric filters are the more economic choice for low-sulfur coals and electrostatic precipitators for high-sulfur coals.

E. Field Experiences

A telephone survey was taken to investigate the utilities' field experience on the performance of electrostatic precipitators and/or fabric filters. With few exceptions, only those utilities which are located in the western region of the United States and burn low-sulfur coals, are included in the survey. A list of utilities that have been contacted are given as follows:

Arizona Public Service

Colorado - Ute Electric Association, Inc.

Commonwealth Edison Co.

Department of Public Utilities, City of Colorado Springs

Houston Power and Light

Nebraska Public Power District

Nevada Power Co.

Otter Tail Power Co.

Public Service of Colorado

Public Service of New Mexico

Salt River Project

San Antonio Public Service Board

Sierra Pacific Power Co.

Southern California Edison Co.

Southwestern Public Servie Co.

Texas Utilities Services, Inc.

Utah Power and Light

Also, contacts were made to several architecture and engineering firms and a research institute for design information. They are:

Bechtel Power Co.

Black and Veatch

Brown and Root

Industrial Clean Air, Inc.

Stearns-Roger, Inc.

Stone and Webster

Electric Power Research Institute

Many utilities have field experiences with both electrostatic precipitators and fabric filters, and their general opinions can be summarized by the following:

1. All of the utilities surveyed had a visible plume problem with electrostatic precipitators even though some of them could marginally comply with particulate emission regulations; those with fabric filters claimed clear stacks almost all the time.

2. Hardly any electrostatic precipitators surveyed met the particulate emissions regulations all the time. They might comply right after being washed and "tuned up", but gradually deteriorated to violate the regulations.

3. The reason given by those who selected fabric filter was always that they had unsatisfactory experiences with precipitators; those who operated fabric filters never expressed their dissatisfaction with them. As a matter of fact, all utilities which had installed fabric filters, selected the same equipment for their future plants.

4. The only problem with fabric filters is the high pressure drop, as experienced with Southwestern's Harrington Unit 2. But, the problem is solvable with the use of proper cleaning methods and the specification of a lower air-to-cloth ratio.

5. All people contacted favored fabric filters over precipitators, especially when firing Western coals and under today's strict regulations.

The survey clearly shows two things: first, the utilities have already established confidence on fabric filter's performance; second, with regard to opacity and high collection efficiency, fabric filters are definitely better than electrostatic precipitators.

F. Future Trend for Western Coal Applications

Electrostatic precipitator have been used by electrical utilities as the particulates control equipment for many years, but recently, fabric filters are rapidly catching up especially in the western states where low-sulfur coals are the primary source of fuel. In fact, utilities in the western states have committed more fabric filters than electrostatic precipitators for their future generating units.

An investigation of western utilities' future installation of particulate collection devices shows that units with a total of 7,250 MW capacity have already selected fabric filters, with 2,400 MW leaning in this direction. Table 8 gives a list of units committed to fabric filters in the future. Table 9 presents a list of western utilities which selected precipitators for their future plants, totalling 3,840 MW capacity.

By comparing data from Table 8 and Table 9, several interesting facts are revealed:

1. The generating capacity committed to fabric filters is more than double those committed to precipitators.

2. No precipitator was purchased for installation beyond year 1981.

3. Most stations which previously selected precipitators have switched to fabric filters for their newer units. For example, Craig Nos. 1 and 2 were installed with precipitators, but Craig No. 3 will have fabric filters; Parish No. 7 has a precipitator, but Parish No. 8 will have a fabric filter; Gentleman Nos. 1 and 2 have precipitators, but Gentlemen No. 3 will have a fabric filter; Hunter Nos. 1 and 2 have precipitators, but Hunter Nos. 3 and 4 will have fabric filters, Coronado Nos. 1 and 2, which the Department is a partial owner, have precipitators, but Coronado No. 3 will have a fabric filter.(12)

The future trend for western utilities clearly indicates that the fabric filter is a more favorable choice than the precipitator.

G. Other Considerations

1. Combined with SO_2 Dry Scrubbers

IPP now is considering the use of a dry scrubber for SO_2 removal. If the dry scrubber is selected, the fabric filter is a natural choice for the particulate removal device since most manufacturers use the dry scrubber and the fabric filter as a package. Some manufacturers have suggested the combination of dry scrubber with a precipitator. The feasibility of this combination is uncertain because the dry scrubber makes the coal ash properties even more complicated before entering the precipitator.

2. Availability and Reliability

No utility keeps complete availability data for precipitators or fabric filters, because it is so difficult to estimate availability of one single piece of equipment when so many others are involved in the power plant operation. But it can generally be expected that the availability of a fabric filter is better than a precipitator, because on-line maintenance is possible for fabric filter operation but is not practical for a precipitator.

3. Simplicity

Fabric filters are based on a very simple method of filtering without complicated control equipment. A simple equipment is less problem prone and easy to operate. Comparatively, the precipitator is a more complicated piece of equipment.

4. Regulatory Agencies' Opinion

Based on conversations with Utah state agencies and Utah Power and Light, it appears that the State Regulatory Agencies are in favor of fabric filters.(13)

5. Base load Unit or Cycling Unit

The fabric filter is best applied to a base load unit. For a cycling unit, the fabric filter is not a good choice. The cycling unit usually goes through the acid dewpoint many times because of the variation of loads. This will damage filter bags and shorten bag life.

V. Conclusion and Recommendation

After dominating the electric utility industry as the particulate control for many years, the electrostatic precipitator has been giving ground to the fabric filter, especially in the western states. As discussed in the previous section, more and more western utilities have switched from electrostatic precipitators to fabric filters. For the generally conservative utility industry, this significant shift means that the performance of fabric filters are superior to the precipitators for future applications.

One major weakness of the fabric filter, as commonly recognized, is its lack of extensive experience on utility boilers. However, the existing fabric filters, which have accumulated installed capacity of more than 1,000 MW, have a very satisfactory operating record. As more and more fabric filters are put on-line, their performance has shown encouraging results.[(14)(15)] It appears that the fabric filter has already built its own case so that the lack of extensive utility experience should not be considered as an important factor anymore.

This report compares electrostatic precipitators and fabric filters covering such factors as coal properties, particulate collection efficiency, opacity, utilities' field experiences, costs, trend for future applications, and many others. The results shown are overwhelmingly in favor of fabric filters. Thus, this study concludes that the fabric filter is recommended for IPP as the particulate collection device.

VI TABLES

TABLE 1. INVESTMENT AND ANNUALIZED COSTS FOR FABRIC FILTERS AND ELECTROSTATIC PRECIPITATORS. (EPA ESTIMATES)

Fabric Filter

Boiler Size (MW)	Air-to-Cloth Ratio ($acfm/ft^2$)	Investment ($/kW)	Annualized Cost (mills/kWh)
200	2	69.47	2.30
500	2	58.45	1.96
1,000	2	53.56	1.81

Electrostatic Precipitator

Boiler Size (MW)	Specific Collection Area ($acfm/ft^2$)	Investment ($/kW)	Annualized Cost (mills/kWh)
100	400	76.06	3.59
500	400	52.53	2.46
1,000	400	50.15	2.34
100	550	90.67	4.29
500	550	68.45	3.21
1,000	550	65.13	3.04
100	650	98.22	4.65
500	650	80.71	3.77
1,000	650	73.37	3.43

TABLE 2 BUDGETARY COST DATA PROVIDED BY 10 EQUIPMENT VENDORS
(FOR ONE IPP BOILER UNLESS NOTED OTHERWISE)

Equipment supplier	Collector type	Cleaning Method*	SCA ($ft^2/10^3$ acfm)	A/C1 (ft/min)	Equipment cost 10^6 dollars	Total installed cost 10^6 Dollars	Total installed cost $/acfm
A	FF	RA	-	2.5/1	7.0	12.65	3.78
	cold ESP	-	686	-	14.0	23.0	6.87
B	FF	RA	-	2.0/1	7.45	-	-
	cold ESP	-	690	-	7.9	-	-
C	cold ESP	-	825	-	15.365	-	-
D	cold ESP	-	966	-	23.182	-	-
E	FF	RA	-	2.52/1	11.614	16.899	6.35
F	FF	RA	-	2.33/1	-	56.0 +	5.26
	cold ESP	-	595	-	-	54.9 +	5.08
G	cold ESP	-	595	-	10.962	-	-
H	FF	RA	-	2.04/1	10.2	18.435	6.93
	cold ESP	-	780	-	14.55	23.995	9.02
I	FF	P	-	5/1	12.8	-	-
J	cold ESP	-	560	-	60.0 +	76.0 +	7.14

*RA = reverse air
P = pulse
+Price given for all four boilers.

TABLE 3 ANNUALIZED COST ESTIMATE FOR AN ELECTROSTATIC PRECIPITATOR INSTALLED ON ONE IPP BOILER (GCA ESTIMATES)

Direct costs	
Direct (operating) labor	16,400
Supervision labor	3,416
Maintenance labor	41,000
Maintenance materials and replacement parts	51,660
Electricity	436,303
Waste disposal	1,135,525
TOTAL DIRECT COSTS	$1,684,304
Overhead	
Payroll	4,920
Plant	29,244
TOTAL OVERHEAD	$ 34,164
Capital Charges	
G & A, taxes and insurance	959,800
Capital recovery factor	2,178,746
Interest on working capital	27,370
TOTAL CAPITAL CHARGES	$3,165,916
TOTAL ANNUALIZED COST	$4,884,384
mills/kWh	1.05

TABLE 4 ANNUALIZED COST ESTIMATE FOR A FABRIC FILTER INSTALLED ON ONE IPP BOILER (GCA ERSTIMATES)

<u>Direct costs</u>	
Direct (operating) labor	30,748
Supervision labor	6,833
Maintenance labor	44,413
Maintenance materials and replacement parts	432,250
Electricity	535,948
Waste disposal	1,135,525
TOTAL DIRECT COSTS	$2,185,717
<u>Overhead</u>	
Payroll	9,224
Plant	133,703
TOTAL OVERHEAD	$ 142,927
<u>Capital Charges</u>	
G & A, taxes and insurance	737,400
Capital recovery factor	1,673,898
Interest on working capital	35,518
TOTAL CAPITAL CHARGES	$2,446,816
TOTAL ANNUALIZED COST	$4,775,460
mills/kWh	1.02

TABLE 5 RANGE OF COAL SAMPLE DATA
Intermountain Power Project

Coal Properties - Proximate Analysis, % Weight as Fired

Total Moisture	4.5 - 11.0
Volatiles	36.14 - 42.34
Fixed Carbon	39.50 - 49.11
Ash	4.29 - 9.48

Ultimate Analysis, % Weight as Fired

Carbon	62.35 - 75.42
Hydrogen	4.32 - 5.30
Oxygen	9.26 - 14.93
Nitrogen	1.02 - 1.46
Sulfur	0.44 - 0.78
Moisture	4.50 - 10.46
Ash	4.29 - 9.77
Chlorine	0.0 - 0.02

Ash Analysis, % Weight

Fe_2O_3	3.53 - 10.75
CaO	4.82 - 20.65
MgO	0.96 - 4.68
K_2O	0.22 - 1.21
Na_2O	0.07 - 3.88
SO_3	3.38 - 14.63
P_2O_5	0.04 - 0.51
SiO_2	35.88 - 65.43
Al_2O_3	8.34 - 18.21
TiO_2	0.26 - 1.04

Fusion Temp. (Reducing) ^{o}F

Initial Deformation	2085 - 2380
Softening (H=W)	2100 - 2410
Softening (H=1/2W)	2120 - 2475
Fluid	2135 - 2590

Fusion Temp. (Oxidizing) ^{o}F

Initial Deformation	2130 - 2425
Softening (H=W)	2140 - 2435
Softening (H=1/2W)	2160 - 2445
Fluid	2170 - 2455

TABLE 6 SURVEY OF PRECIPITATOR PERFORMANCE ON U.S. WESTERN COALS

Utility (Station, Unit Number)	Capacity (MW)	Design Efficiency (%)	Test Efficiency (%)
Public Service Co. of Colorado			
Comanche No. 1	350	99.6	99.18
Comanche No. 2	350	99.6	99.18
Wisconsin Power & Light, Co.			
Columbia No. 1	520	99.5	91
Iowa Public Service, Co.			
George Neal No. 1	138	99.0	91
Commonwealth Edison			
Will County No. 3	299	98.5	99
Waukegan No. 7	360	99.1	98.7 - 99.7
Salt River Project			
Navajo No. 1	750	99.5	98.8 - 99.1
Navajo No. 2	750	99.5	98.8 - 99.1
Navajo No. 3	740	99.5	98.8 - 99.1
Public Service of New Mexico			
San Juan No. 1	330	99.5	99.8
San Juan No. 2	330	99.5	99.8
Iowa Power & Light, Co.			
Des Moines No. 10	71	99.3	99.3
Des Moines No. 11	116	99.3	99.5
Council Bluffs No. 1	47	99.3	98.0
Council Bluffs No. 2	90	99.3	98.3

TABLE 6 SURVEY OF PRECIPITATOR PERFORMANCE ON U.S. WESTERN COALS (Cont'd)

Utility (Station, Unit Number)	Capacity (MW)	Design Efficiency (%)	Test Efficiency (%)
Colorado - Ute. Elec., Inc.			
Hayden No. 1	200	99.6	99.19
Hayden No. 2	250	99.6	97 or 98
San Antonio Public Service Board			
J. I. Deely No. 3	430	99.4	86 - 91
J. I. Deely No. 4	430	99.4	86 - 91
Omaha Public Power Dist.			
Wright No. 8	90	99.3	99
Nebraska Public Power Dist.			
Sheldon No. 1	105	97.9	97.2 - 97.6
Sheldon No. 2	120	97.9	97.2 - 97.6
Colorado Spring Department of Public Utilities			
Martin Drake No. 7	137	99.35	99.2
Arizona Public Service			
Four Corners No. 4	750	97	92 - 94
Four Corners No. 5	750	97	92 - 94
Southern California Edison			
Mohave No. 1	790	97.9	97 - 98.6
Mohave No. 2	790	97.9	97 - 98.6

TABLE 7 SUGGESTED COLLECTING EFFICIENCIES OF FABRIC FILTER AND ELECTROSTATIC PRECIPITATOR BASED ON PARTICLE SIZE DISTRIBUTION

Particle Size	Fabric Filter Efficiency (%)	Electrostatic Precipitator Efficiency (%)
0.3	99.8	95.19
0.5	99.8	95.1
1.0	99.8	96.32
2	99.8	99.26
3	99.8	99.37
5	99.8	99.59
7	99.8	99.79
10	99.8	99.93

TABLE 8 FUTURE INSTALLATION OF FABRIC FILTERS IN THE WESTERN UNITED STATES

Utility (Units)	Size (MW)	Manufacturer	On-Line Date
Arizona Public Service			
Four Corners No. 4	750	Buell	1981
Four Corners No. 5	750	Buell	1981
Basin Electric Power Corporation			
Antelope Valley No. 1	440	Western Precipitation	1982
Antelope Valley No. 2	440	" "	1983
City of Colorado Springs			
Nixon No. 1	200	Western Precipitation	1980
Colorado-Ute Elec. Assoc.			
*Craig No. 3	400		
Houston Power and Light			
Parish No. 8	550	Research Cottrell	1983
Nebraska Public Power Dist.			
*Gentleman No. 3	650		
Nevada Power Co.			
Reid Gardner No. 4	250	Carborundum	1983
Otter Tail Power Co.			
Coyote No. 1	440	Western Precipitation	1981
Public Service of Colorado			
Cherokee No. 2	100	Buell	1980
Cherokee No. 3	150	Buell	1980
*Southeast No. 1	500		
*Southeast No. 2	500		

TABLE 8 FUTURE INSTALLATION OF FABRIC FILTERS IN THE WESTERN UNITED STATES (Cont'd)

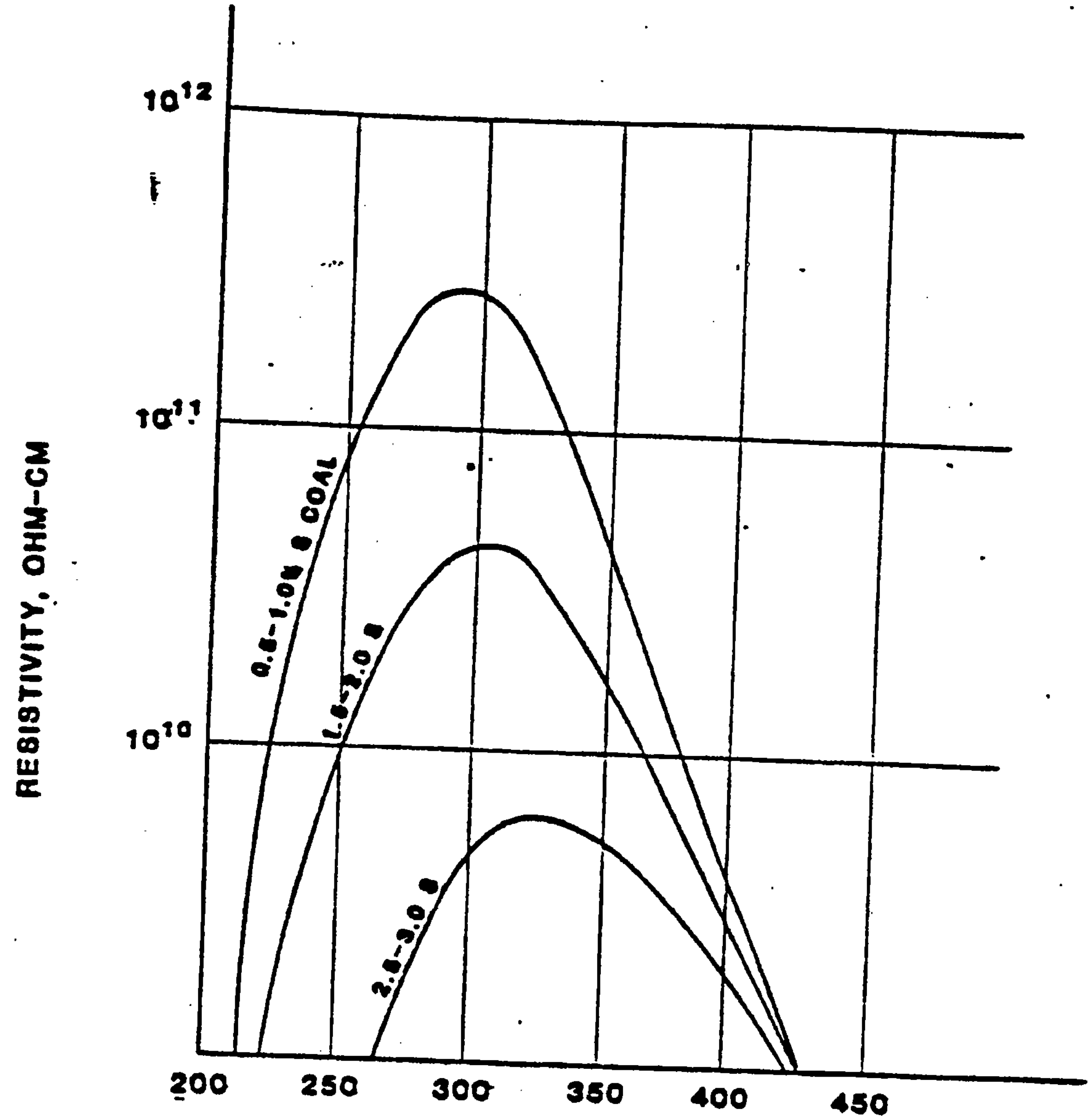
Utility (Units)	Size (MW)	Manufacturer	On-Line Date
Salt River Project			
*Coronado No. 3	350		
Sierra Pacific Power			
North Valmy No. 1	250	Carborundum	1980
*North Valmy No. 2	250		
Southwestern Public Service			
Tolk No. 1	550	Industrial Clean Air	1982
Tolk No. 2	550	" " "	1984
Tucson Electric Power			
Springville No. 1	350	Western Precipitation	1985
Springville No. 2	350	Western Precipitation	1986
Utah Power and Light			
Hunter No. 3	440	Carborundum	1983
Hunter No. 4	440	"	1985

*No contract awarded yet but leaning toward fabric filter

TABLE 9 FUTURE INSTALLATION OF ELECTROSTATIC PRECIPITATORS IN THE WESTERN UNITED STATES

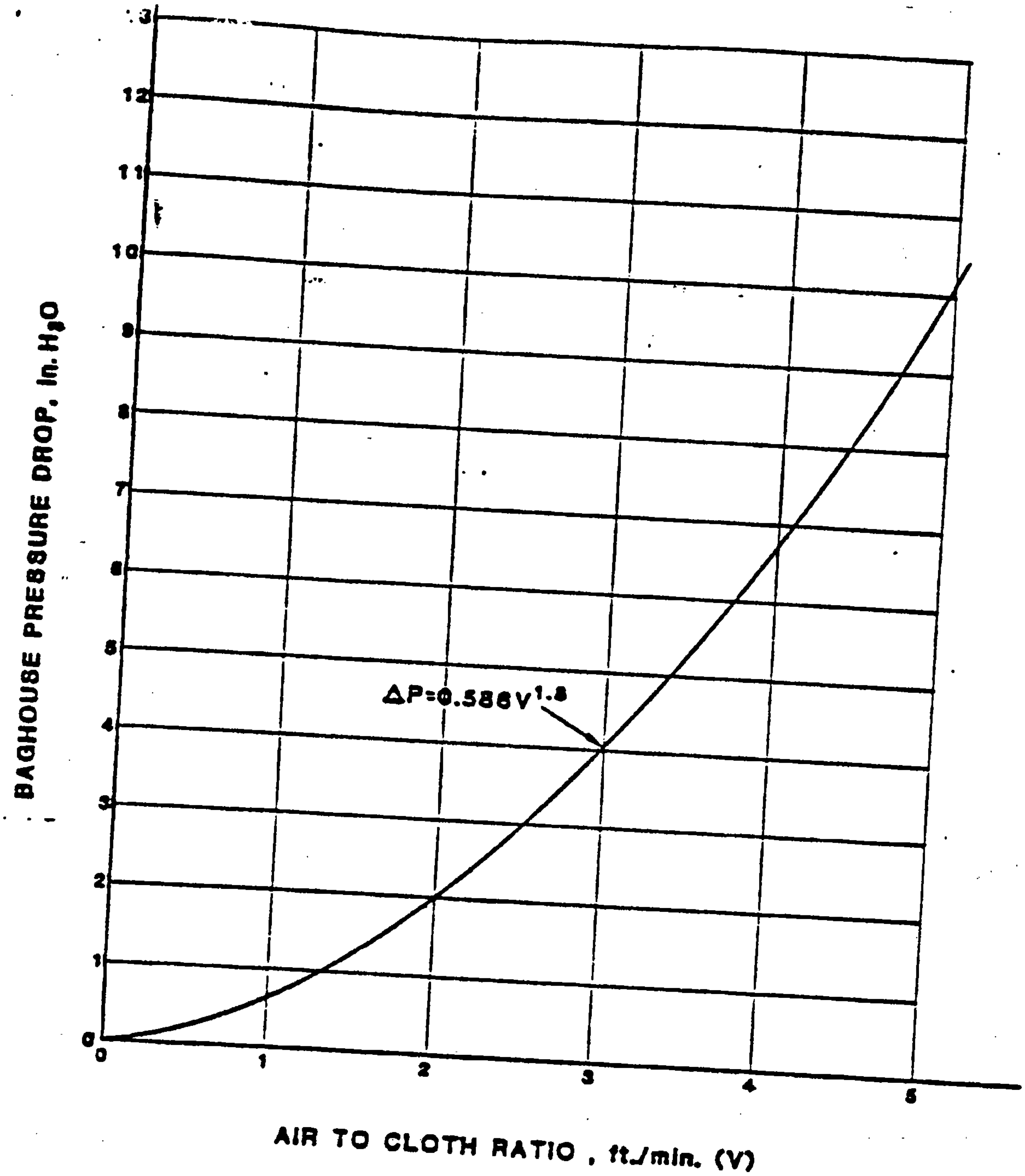
Utility (Units)	Size (MW)	Manufacturer	On-Line Date
Arizona Public Service			
Cholla No. 4	350	Universal Oil Prod.	1981
Colorado-Ute. Elec. Assoc.			
Craig No. 1	410	NA	1981
Houston Lighting and Power			
Parish No. 7	550	Western Precipitation	1980
Nebraska Public Power Dist.			
Gentleman No. 2	680	Environmental Elements	1981
Salt River Project			
Coronado No. 2	350	Western Precipitation	1980
Southwestern Elec. Power			
Welsh No. 2	550	Research Cottrell	1980
Texas Power and Light			
Sandow No. 4	550	C-E Walther	1980
Utah Power and Light			
Hunter No. 2	400	Buell	1980

VII FIGURES



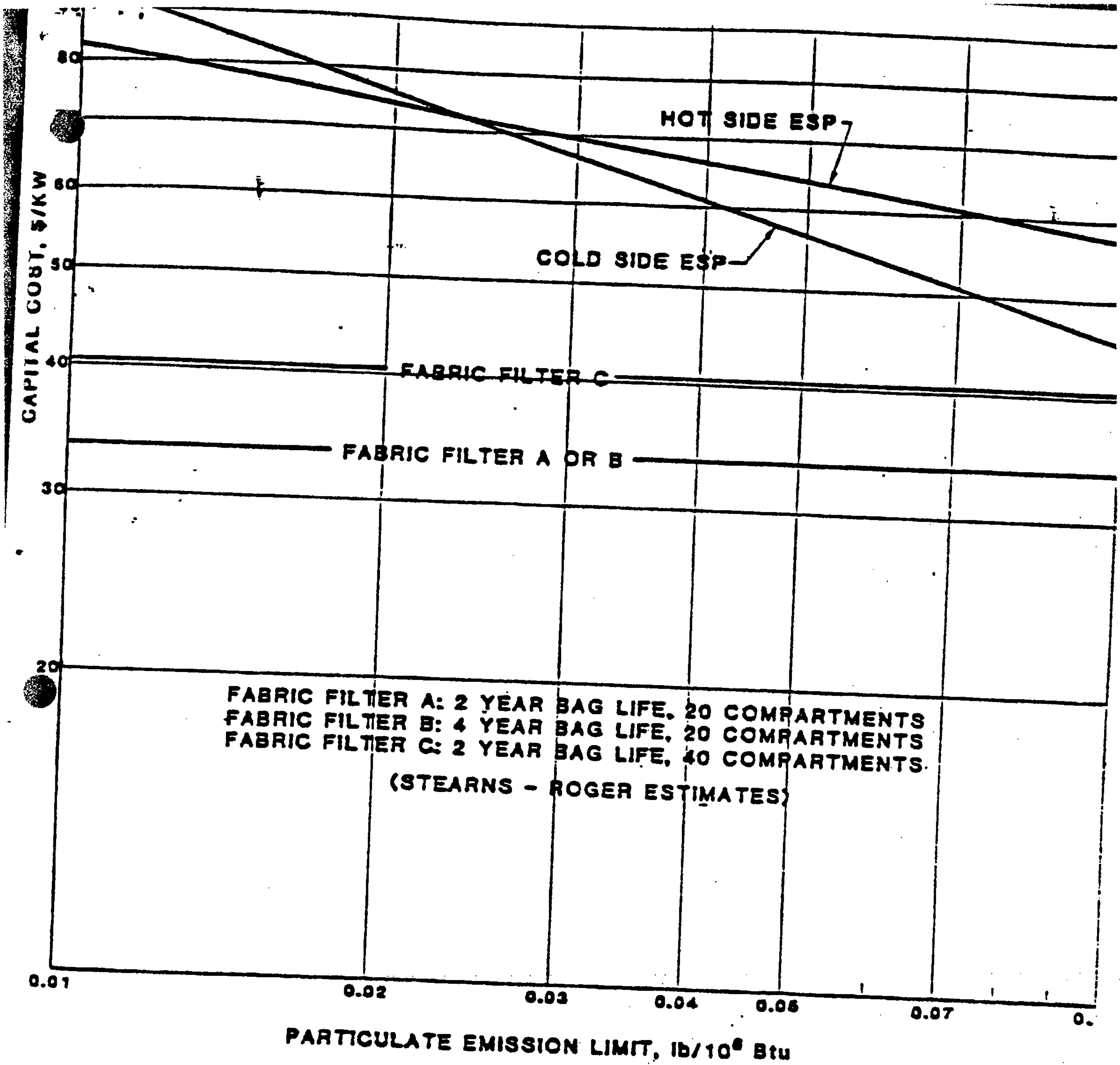
RESISTIVITY, TEMPERATURE, FUEL
SULFUR RELATIONSHIPS

FIGURE 1



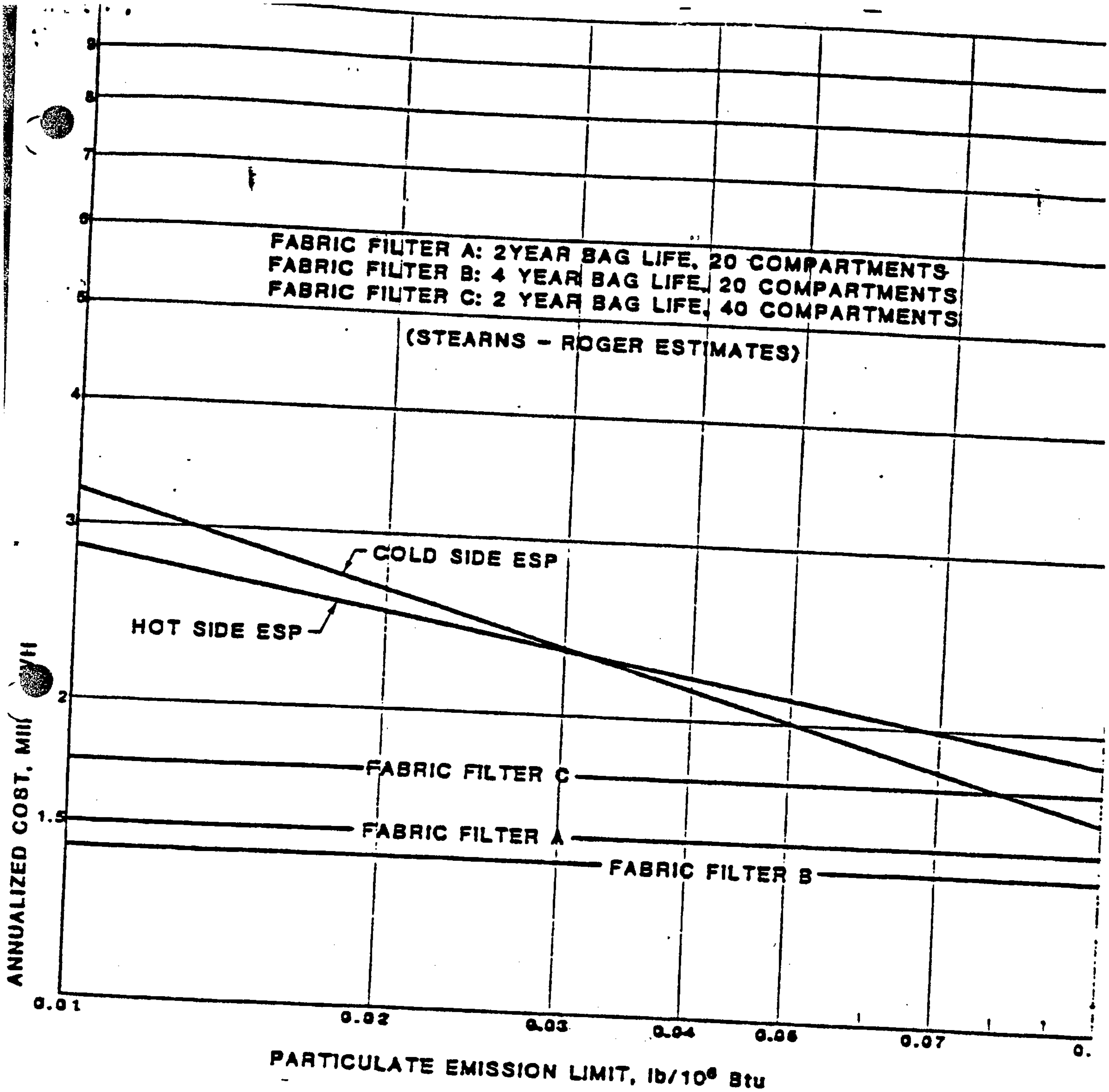
BAGHOUSE PRESSURE DROP VERSUS
AIR TO CLOTH RATIO

FIGURE 2



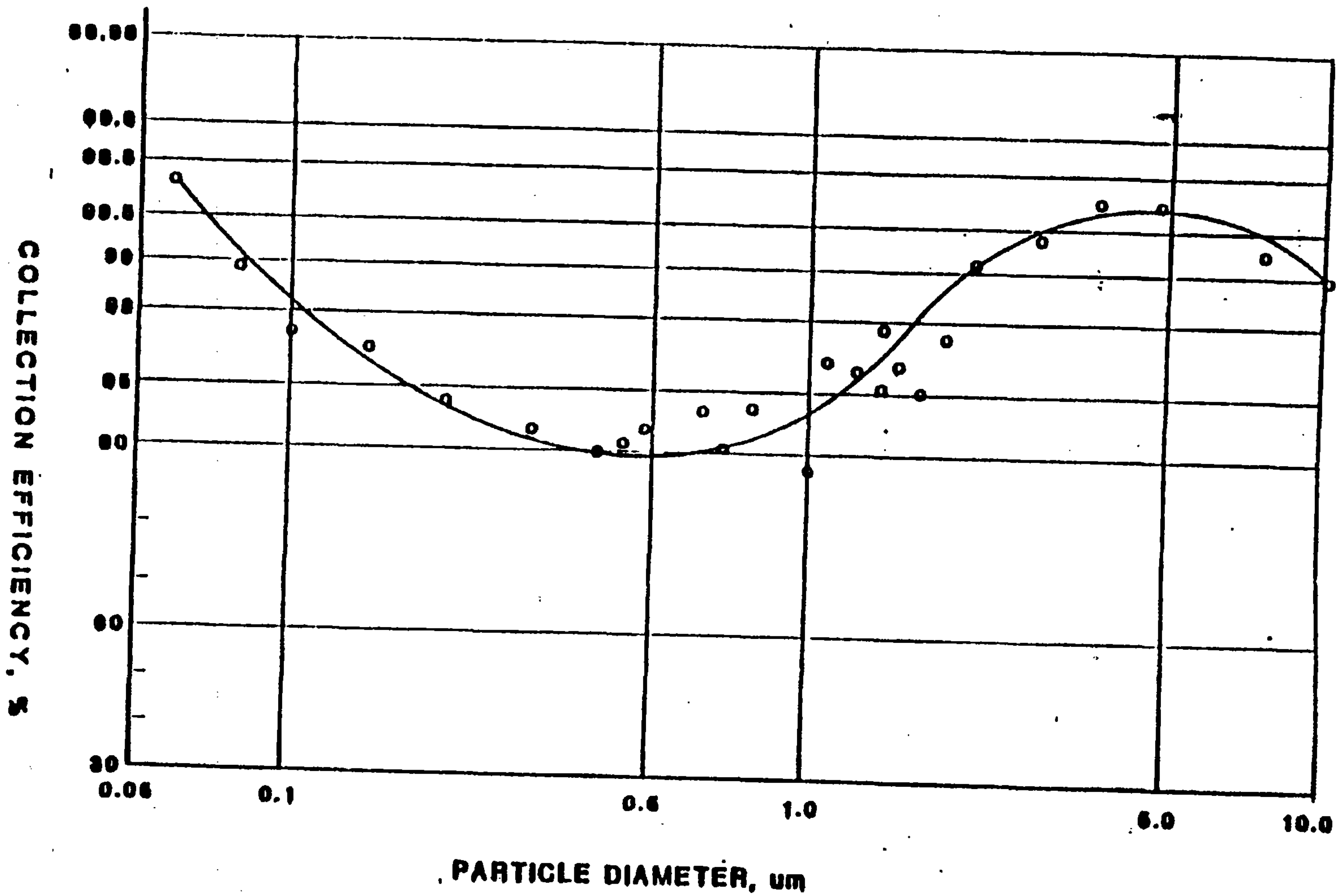
CAPITAL COSTS FOR 500 MW PARTICULATES COLLECTORS IN 1980 DOLLARS

FIGURE 3



ANNUALIZED COSTS FOR 500 MW PARTICULATES COLLECTORS IN 1980 DOLLARS

FIGURE 4



MEASURED FRACTIONAL EFFICIENCIES FOR A COLD-SIDE PRECIPITATOR WITH A BOILER BURNING LOW SULFUR COAL

FIGURE 5

VIII REFERENCES

REFERENCES

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Technical Paper

The specification & design of high availability boilers for the Intermountain Power Project

R. L. Nelson
Assistant Project Engineer
Intermountain Power Project
Los Angeles Department of
Water and Power
Los Angeles, California

H. K. Smith
Marketing Manager
Fossil Power Generation Division
The Babcock & Wilcox Company
Barberton, Ohio

R. P. Siegfried
Project Manager
Fossil Power Generation Division
The Babcock & Wilcox Company
Barberton, Ohio

Presented to
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Engineering & Operating Conference
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March 18, 1982

PGTP 82-17

Babcock & Wilcox
a McDermott company

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R. L. Nelson, Assistant Project Engineer
Intermountain Power Project
Los Angeles Department of Water and Power
Los Angeles, California

H. K. Smith, Marketing Manager
Fossil Power Generation Division
The Babcock & Wilcox Company
Barberton, Ohio

R. P. Siegfried, Project Manager
Fossil Power Generation Division
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Background

The Intermountain Consumer Power Association (ICPA) located in Sandy, Utah, was the spearhead organization behind the Intermountain Power Project (IPP). ICPA has members in Utah, Nevada, Wyoming and Arizona. ICPA was granted Single Purchasing Agency status by the Secretary of the Interior in 1964 to purchase Colorado River Storage Power (CRSP) at the major federal points in Utah for delivery to its members.

When informed that additional CRSP power would not be available to meet their anticipated load growth, the ICPA began investigating alternative sources of power including the possibility of developing its own generation, utilizing the abundant Utah coal supplies.

Other utilities within and outside of Utah, including several California utilities, were contacted concerning their interest and participation in the development of a large coal-fired project in Utah.

In early 1974 a feasibility study for the IPP was initiated and, following the completion of this study, the Intermountain Power Agency (IPA) was formed as a means of financing IPP. As a political subdivision of the state of Utah, IPA was enabled to sell bonds for the construction of IPP and in turn sell the power to the project participants. The participants include a combination of 36 municipal and investor-owned utilities within the states of Utah and California.

Project history

When the initial primary site, near Cainsville, Utah, at Salt Wash, Utah, was found to have required an air quality variance, an Interagency Task Force on Power Plant Siting was created by the governor of the state of Utah. Participants included representatives of the federal government, the state of Utah, industrial and environmental interest groups. This task force ultimately proposed two alternative sites that would not require an air quality variance. In March 1978, the alternative site in the vicinity of Lynndyl, in Millard County, Utah was selected and environmental studies were authorized in order to incorporate the Lynndyl site as an alternative in the Environmental Statement.

The final Environmental Statement was filed with the Environmental Protection Agency (EPA) and on December 19, 1979, federal approval of the Lynndyl site was given, including the issuance of the necessary right-of-way grants for project facilities on lands under the authority of the Bureau of Land Management. The project site location is shown in Figure 1. Specifications for the steam generators were issued in October 1980 with bids received in January 1981. The contract for the boilers was awarded May 5, 1982.

The first unit of IPP is scheduled to be placed into commercial operation in July 1986, with the three additional units scheduled at 12-month intervals, thereafter. A photo of a plant model is shown in Figure 2.

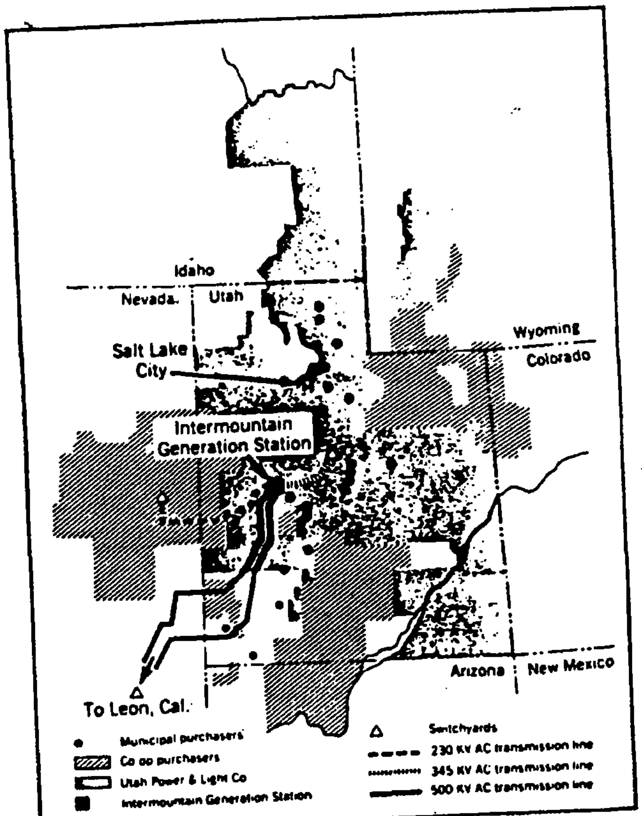

Figure 1 IPP site location.

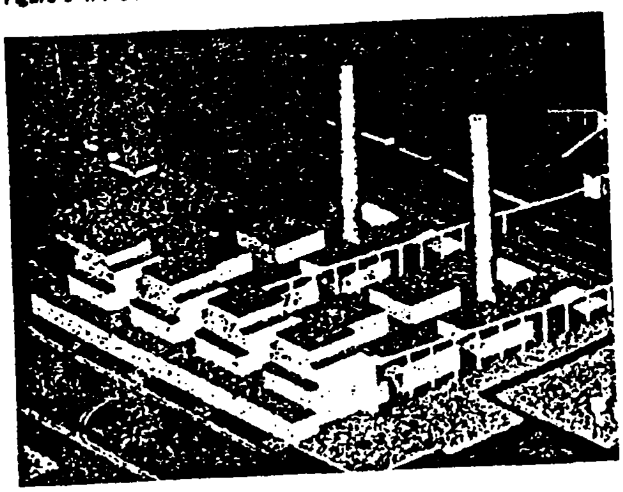

Figure 2 Plant model.

Boiler specifications and evaluation factors

In the process of preparing the specifications, the IPP project team made a concentrated effort to incorporate specific design features, and/or design criteria, that would improve boiler maintainability and availability so as to minimize the frequency and duration of forced outages.

An investigation of boiler component availability was made and Table 1 is representative of a high level component analysis. It ranks, in order, boiler components and their associated industry failure rates.

In order to address these areas of boiler forced outages and load reductions, the project adopted a very conservative design approach. For numerous components, conservative design parameters and material selections were specified. Also, features for improved access and maintainability were incorporated. The following discussion highlights some of these features.

Constant and variable pressure operation: Many utilities are now requiring that new boilers be designed for variable pressure operation. Variable pressure operation permits faster start-up and better matching of turbine metal/steam temperatures than constant pressure boilers. Variable pressure boilers are also designed to accept more thermal cycles because of the anticipated increased number of start-ups, shutdowns, or load ramping.

Furnace plan heat release rate: An investigation was conducted of the furnace plan heat release (FPHR) rate as a function of boiler availability and coal characteristics. It was determined that the maximum FPHR rate for optimum availability at reasonable cost and operating flexibility was a

Table 1 Major causes of boiler outages

	All fossil units - full outage losses and estimated partial outage losses (%)
Boiler tubes	5.8
Fuel handling equipment	1.9
Continuous deratings	1.5
Fans	1.1
Slag, ash & fouling	1.1
Air preheaters	0.7
Emission controls	0.7
Burners	0.2
Other	2.3

EPRI NP-1191 Sept. 1979

value of 1.6 million BTU/ft² hr measured on a fuel input basis as defined by:

$$\text{FPHR} = \frac{\text{Input in Fuel Btu/hr}}{\text{Furnace Plan Area - Ft}^2}$$

Top burners to furnace platens: As part of the studies into furnace design, considerable thought was given to the distance between the top row of burners and the bottom of the furnace platens. Although this is somewhat dependent on steam temperature-control method and firing system employed, conservative design dictates the avoidance of high platen inlet gas temperatures and raises the platens; yet, first cost and operating characteristics bring the platens down. With due consideration of fuel characteristics, 80 feet was selected as the minimum for this project.

Convection tube spacing: Side-to-side clear tube spacing of 3 inches was specified to minimize backend pluggage. Tube banks were also arranged in-line, rather than staggered, to assure that deposits removed by sootblowers would fall to the economizer hoppers.

Gas velocity: Surveys indicated that many coal-fired units suffered from gas side erosion. The potential effects of erosion were minimized by specifying a maximum gas velocity of 55 feet per second.

Gas temperature: The gas temperature entering the close-spaced platen or pendant surfaces shall not be greater than 1900 F HVT at maximum continuous rating (MCR).

Metal selection: Metal selection criteria for pressure and non-pressure parts was reviewed for optimum availability.

The following major tube metal selection criteria were specified:

ASME specification	Maximum external metal temperature, °F
SA-213 Grade T2	950
SA-213 Grade T11	1,000
SA-213 Grade T21	1,075
SA-213 Grade T22	1,075
SA-213 Grade T9	1,150
SA-213 Grade T321H	1,400
SA-213 Grade T347H	1,400

The use of carbon steel was limited to 775°F at pressures greater than 50 psig, and a maximum of 825°F at pressures below 50 psig.

The use of SA209 Grade T1a material was prohibited altogether.

Bare economizer tubes: Finned economizers have been a source of ash pluggage and resulted in difficult maintenance for many utilities. Therefore, the economizer design was specified as bare tubes. As with other convection surfaces, the specifications also required that the economizer tubes be in line to minimize plugging and erosion.

Duct gas velocities: To avoid excessive pressure drop and duct vibrations, duct gas velocities were restricted to 50 feet per second.

Spare pulverizer capacity: Poor coal quality and pulverizer performance are major contributors to unit deratings. To compensate for these facts, the specifications required that the boiler be furnished with adequate pulverizers to attain full load, having one spare pulverizer and all others in a worn condition, based on a specified coal with poorer overall quality than the design coal. This is a very significant design criteria which should result in greater boiler availability and fuel flexibility.

Coal-air velocity: To reduce the maintenance of coal-air piping due to erosion, the coal-air velocity was restricted to a maximum of 85 feet per second.

Ceramic coal pipe lining: The primary point of erosion wear in coal-air piping is at any elbow and immediately above the pulverizers. To minimize the wear in these areas, ceramic lining was specified.

Stainless steel downspouts: To prevent coal hang-ups between the feeders and the pulverizers, 304 stainless steel downspouts were specified.

P.A. fan capacity: In order to compensate for possible poor fuel quality in the future and additional possible air preheater pressure drop, test block margins of 25 percent on flow and 50 percent on pressure were specified. Each fan was also specified to be capable of providing sufficient primary air to permit boiler operation at 60% of maximum capacity with each of the specified coals.

Access doors and view ports: Once a tube failure occurs, quick access and repair is essential to minimize the forced outage. Therefore, numerous access doors were added in the boiler furnace, penthouse and backpass. Access doors, large enough to accommodate scaffolding, will be installed near the top of the furnace, in the backpass, and in the penthouse. Smaller access doors were also added in the hopper throat and backpass walls. Numerous view ports are required for monitoring burners and platens.

Maintenance space: To facilitate quick repair and access for maintenance, the specifications required sufficient cavities between horizontal banks of tubes for a welder to gain access and work under reasonable conditions.

Burner shutoff valves: To facilitate coal-air piping or burner maintenance while the boiler is on the line, shutoff valves at each burner were specified.

Additional air heater capacity: In addition to the specification of redundant gas/air streams for air heating to allow for air heater degradation and fuel flexibility, the regenerative air heaters were required to be designed for the future addition of 8 inches of heat transfer elements.

Reheat surface adjustment: Since the reheater may occasionally prove to be under-surfaced due to design uncertainties or coal deviation, space was provided to add reheater surface, should this prove necessary, after initial unit operation or in the future.

Table 2 categorizes those features specified for improved availability. The features listed are major design parameters, special provisions for maintainability, and provisions to minimize forced outages.

During the proposal review period, a rigorous economic and comprehensive technical evaluation was made.

The technical evaluation centered around ascertaining each bidder's potential for high availability as related to his design features, design conservatism and in relationship to numerous reference units which are in operation. A technical decision matrix was generated which listed key technical considerations and their relative weighting (see Table 3). Each proposal was then given a relative score for each category, with the best proposal in each category receiving a score of ten. This matrix proved very beneficial in summarizing each proposal's design features and presenting such information to management.

The final phase of the evaluation consisted of an availability evaluation. A consultant with expertise in statistical analyses and familiar with the utility industry was retained for this purpose. Using North American Electric Reliability Council

Table 2 Features for improved availability

Major design parameters

Plan area heat release of 1.6 X 10^6 Btu/ft²/hr.

Maximum gas velocity - 55 fps.

Furnace exit gas temperature - 2115F HVT.

Burner zone heat release rate.

Volume liberation.

80 ft. minimum distance top burner to platen.

Maximum coal air velocity 85 fps.

Special provisions for maintainability

Cera-VAM® ceramic coal pipe lining.

Access doors and view ports.

Large access space between tube banks.

Shutoff valves at coal burners.

Provision for RH surface adjustment.

Features to minimize forced outages

Boiler designed for fast start-up, variable pressure operation.

Lower tube metal temperature limits.

Bare tube economizer.

Two spare pulverizers.

304 stainless steel coal downspouts.

Extra primary air fan capacity.

Minimum RH tube thickness .180".

All seamless boiler tubing.

High waterwall tube mass velocity.

Minimum convection tube clear side, spacing - 3".

Air heaters designed for future surface additions.

Ribbed tubes in furnace area.

Table 3 Technical decision matrix
Intermountain Power project boilers

	Weighting factor
Western coal experience	11
2400 psi - 750 MW experience	10
Tube design conservatism	9
Low NO_x potential	9
No radiant reheater	7
Low slagging potential	7
Low fouling potential	7
Furnace access	4
Backpass access	4
Pulverizer capacity	7
Sootblower maintenance	3
Boiler response rate	4
Same burner experience	4
Burner zone heat input	4
Same pulverizer experience	6
Ribbed tube experience	4
Weighted total	10
Simple total	160

(NERC) data and also information furnished by each bidder in their proposals, a probabilistic analysis of availability was made. These results were combined with a value for replacement energy to ascertain a value for any projected differences in availability.

The final selection of the successful bidder was based upon consideration of all three evaluations — economic, technical and availability. In recognition of each of the bidders, each proposal was very well thought out and represented a very good design. The proposal selected as the best offering for IPP was that made by the Babcock and Wilcox Company.

Boiler description

Each of the four natural circulation, balanced draft, single reheat boilers (Figure 3) are designed for a nominal rating of 6,100,000 lbs/hr of steam at a superheater outlet pressure of 2515 psig and superheater and reheater outlet temperatures of 1005 F. The maximum continuous design steam flow (MCF) is 6,600,000 lbs/hr at a superheater outlet pressure of 2640 psi with superheat and reheat outlet temperatures of 1005 F. (Additional boiler performance data is shown in Table 4). The radiant boilers are of the Carolina design (RBC) with steam temperature control by gas biasing and spray attemperation. Each steam generator supplies a General Electric turbine generator having a nominal rating of 820 MW. The net unit output is 750 MW. Each unit will be totally enclosed.

The furnace is of the dry bottom type and is 85' wide, 60' deep. The top of the top support steel is 288 ' above grade.

The design pressures for the furnace and superheater, reheater, and economizer are 2975 psi, 750 psi, and 3050 psi, respectively.

Each unit is equipped with eight MPS-89 pulverizers (Figure 4) arranged with four mills along each side. Each pulverizer supplies a single horizontal row of dual register burners. There are four burner rows in each of the front and rear walls. The unit is capable of operating at MCR on performance coal with two mills out of service.

Additional equipment to be supplied by The Babcock & Wilcox Company (B&W) includes coal feeders with nuclear flow detectors, two primary and two secondary regenerative air heaters, two centrifugal primary air fans and motors, steam sootblowers and the burner management system.

A wet gas scrubber for SO_2 removal and a baghouse for particulate removal, furnished by others, will be located downstream of the air heaters.

The steam drum is 72" I.D. and equipped with cyclone steam separators arranged in four rows (Figure 5). Water from the drum is conveyed to the bottom of the unit via five downcomers from which the flow is then distributed to the lower furnace enclosure wall headers, utilizing multiple connections.

The furnace enclosure is made up of membraned multi-lead ribbed tubes (Figure 6). The unit is designed for a minimum average tube mass velocity of 800,000 lb/ft²/hr which results in a circulation ratio of 3.2

Dry saturated steam from the drum passes, in parallel, through the furnace roof, pendant convection pass and horizontal convection pass sidewalls; after which, it is distributed to the horizontal convection pass front and rear walls as well as the baffle wall which separates the two downflow gas passes at the rear of the unit. The front gas pass contains horizontal reheat surface and the rear gas pass contains the horizontal primary superheater and economizer surface. A schematic of these flow paths is shown on Figure 7.

From the horizontal enclosure wall, steam is fed to the primary superheater inlet bank; then successively to the pendant primary surface, located at the top of the furnace, the platen secondary superheater inlet surface and finally the platen secondary superheater outlet surface. The secondary superheater outlet surface discharges alternately to two outlet headers, with each header having one outlet connection. Discharging alternately to the two outlet headers minimizes the potential for steam temperature unbalance in the two outlet steam connections due to any side

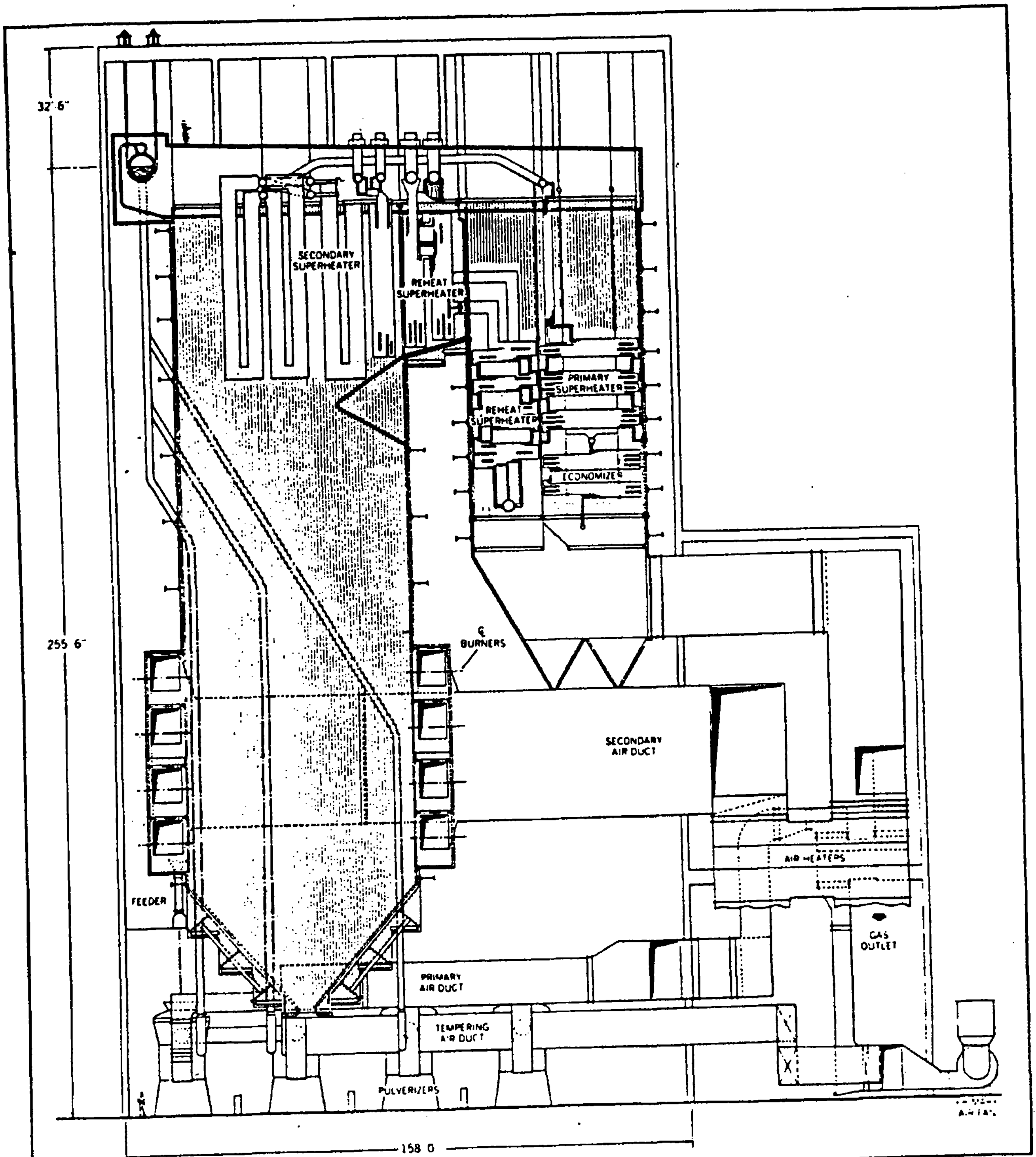

Figure 3 Sectional side view.

unbalanced gas temperature or gas flow. A schematic of this arrangement and side-to-side tube spacing is shown in Figure 8.

Pendant surface alignment is maintained using split ring castings, as shown in Figure 9. These castings eliminate the use of "wrap around tubes" which in the past have been a source of tube erosion and premature tube failures.

Table 4 Boiler performance data

	100% load	MCR
Steam leaving the superheater, lb/hr	6,100,000	6,600,000
Steam leaving the reheater, lb/hr	5,000,000	5,500,000
Excess air leaving the economizer, %	17	17
Fuel input 10^6 Btu/hr	7932	8040
Coal flow, lb/hr	720,400	730,200
Steam pressure at superheater outlet, psig	2515	2640
Steam pressure at reheater outlet, psig	511	562
Steam temperature leaving superheater, F	1005	1005
Steam temperature leaving reheater, F	1005	1005
Flue gas temperature leaving air heater, F	280	280
Water temperature entering economizer, F	543	555
Boiler efficiency, %	88.57	88.45

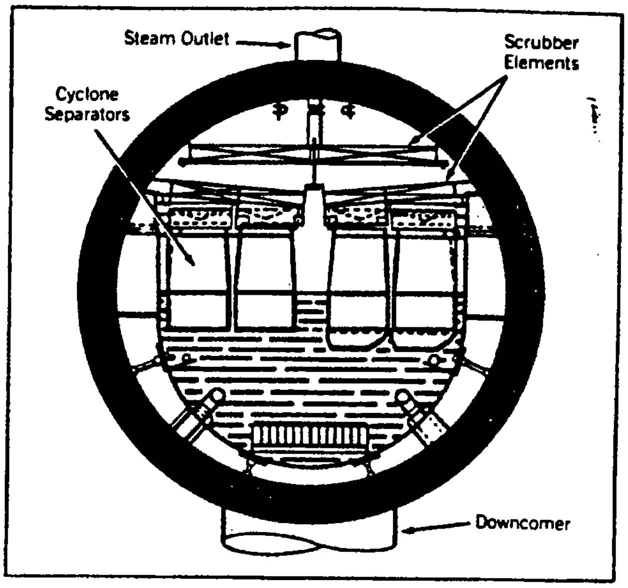

Figure 5 72-inch ID drum.

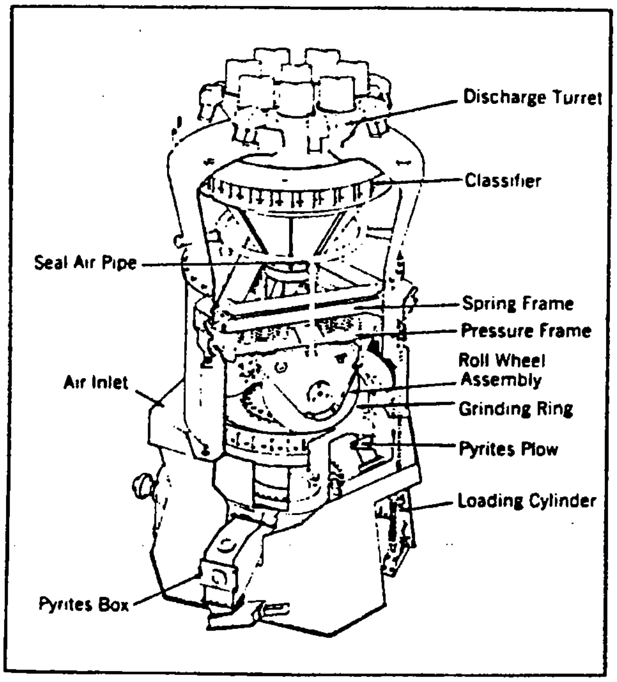

Figure 4 MPS pulverizer.

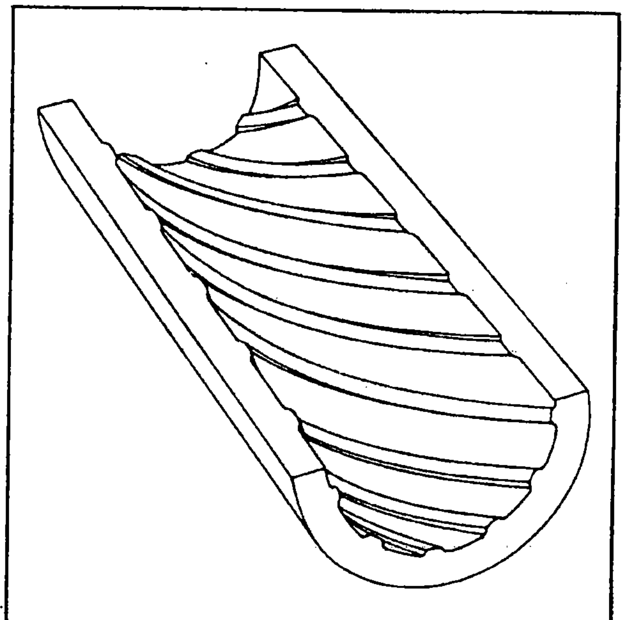

Figure 6 Ribbed tubes.

Spray attemperators for final steam temperature control are located in each of the two cross-over connections between the rear horizontal and pendant primary surface. Spray attemperators are also located in each of two cross-over connections between the pendant primary outlet surface and secondary superheater inlet surface.

All spray attemperators are equipped with two full-size attemperator stations in parallel. Each valve station consists of individual control and block valves.

Cold reheat steam enters the lower reheat inlet header, located at the bottom of the front gas pass, through both ends of the header. Steam then flows upward through the horizontal surface to the pendant reheat surface which also discharges to two reheat outlet headers, each having one outlet nozzle. There are spray

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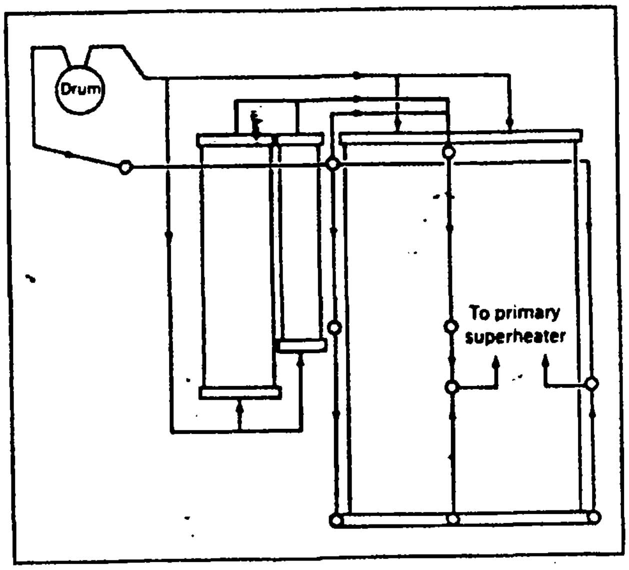

Figure 7 Schematic of convection pass enclosure walls.

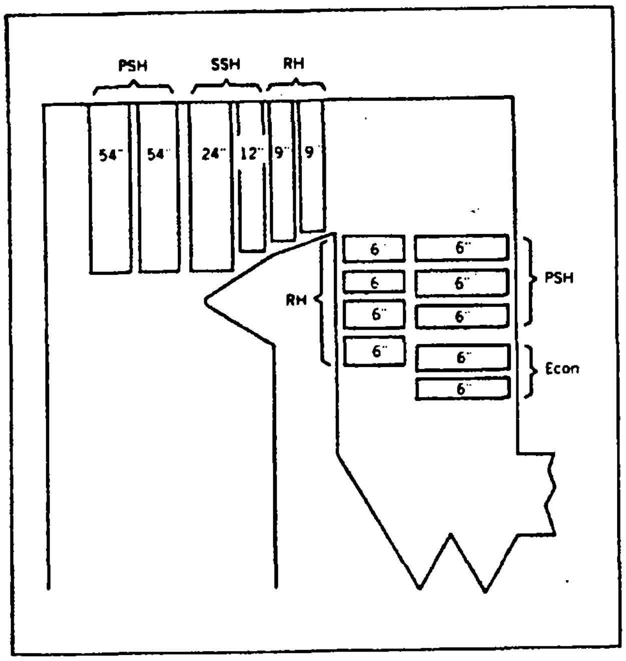

Figure 8 Schematic of convection surface arrangement and tube spacing.

attemperators located in the cold reheat inlet piping for controlling reheat steam temperature under upset conditions, if required.

Reheat steam temperature is controlled down to 65% load by use of biasing dampers, located in the bottom of the downpass, to bias gas flow across the reheater.

The unit is equipped with a compartmented windbox, Figure 10, with each compartment supplying air for a single horizontal row of

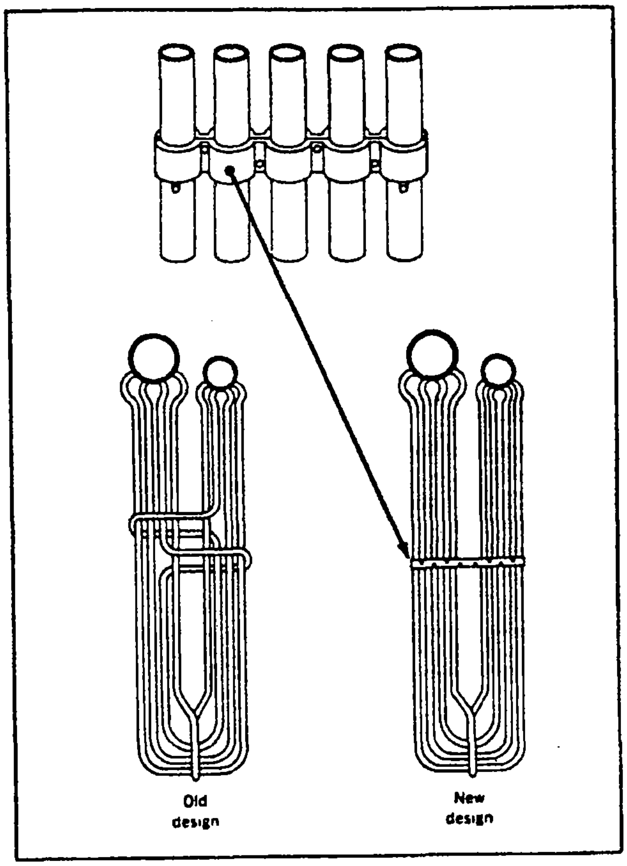

Figure 9 Split ring castings.

burners. Air is admitted from both ends. As a result, air can be controlled on a per compartment basis with all burners within a compartment receiving coal from a single pulverizer.

Coal piping from the pulverizers to the burners are lined with wear resistant Cera-VAM® ceramic material at all elbows to minimize burner line erosion. The vertical discharge coal pipe immediately above each pulverizer is also lined with Cera-VAM® .

Each burner line is equipped with a swing valve at the pulverizer outlet and also at the burner. This will permit isolation of individual burner lines for maintenance purposes, if it should become necessary.

Each of the units is equipped with a partial superheater bypass system to enable better matching of boiler and turbine temperature and to provide a means for positive control of steam conditions during start-up and shutdown. The bypass system, Figure 11, consists of a reheat outlet header attemperator, utilizing high pressure saturated steam as the attemperating medium and a high pressure bypass connection to the condenser. It offers faster cold or hot start-ups,

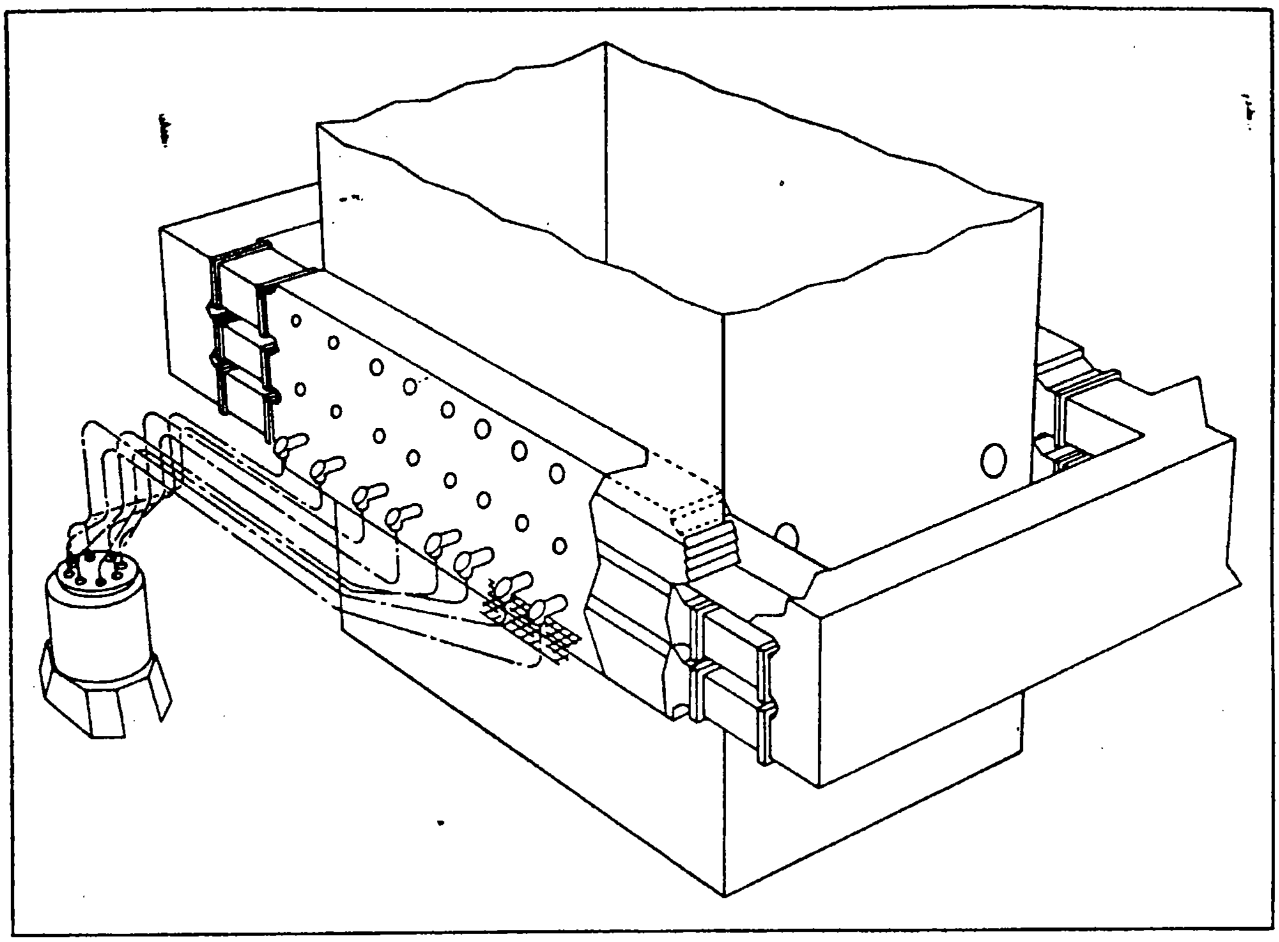

Figure 10 Compartmented windbox.

controlled shutdowns, and minimization of thermal stress on the turbine due to thermal unbalance during start-up and over-the-load range. Specifically, it performs two functions:

- Control of drum pressure by means of a superheater bypass to the condenser.
- Control of reheat outlet steam temperature by means of an attemperator utilizing saturated steam from the drum.

The unit is also arranged for the possible future installation of a full bypass system, Figure 12, which would include isolating valves between the primary and secondary superheater and secondary superheater outlet header attemperator.

Application of the full bypass system would provide the following additional functions:

1. Superheater outlet pressure control with a superheater stop valve and a superheater stop bypass valve. The pressure level at the inlet to the turbine control valves is then independent of the drum pressure over most of the load range.
2. Main steam temperature control during start-up and at low loads, with a superheater outlet steam attemperator and a superheater stop valve and stop valve bypass between the primary and secondary superheater.

The units are designed to fire a range of Utah bituminous coals. Analysis for the performance coal is provided in Table 5. The performance coal is rated as high slagging and high fouling. However, some of the alternate fuels are classified as severe fouling and severe slagging, and this has been taken into consideration in the boiler design.

Each of the dual register burners, Figure 13, is equipped with remote operated air-atomized lighters using No. 2 oil. In addition, each lower row of burners in both the front and rear wall is being equipped with a plasma torch direct coal-ignition system as shown in Figure 14. The use of the plasma torch as a direct ignition source for the coal will enable start-up and stabilization of the fires with minimal use of No. 2 fuel oil.

A complete array of Diamond Power steam sootblowers is being furnished for ash removal

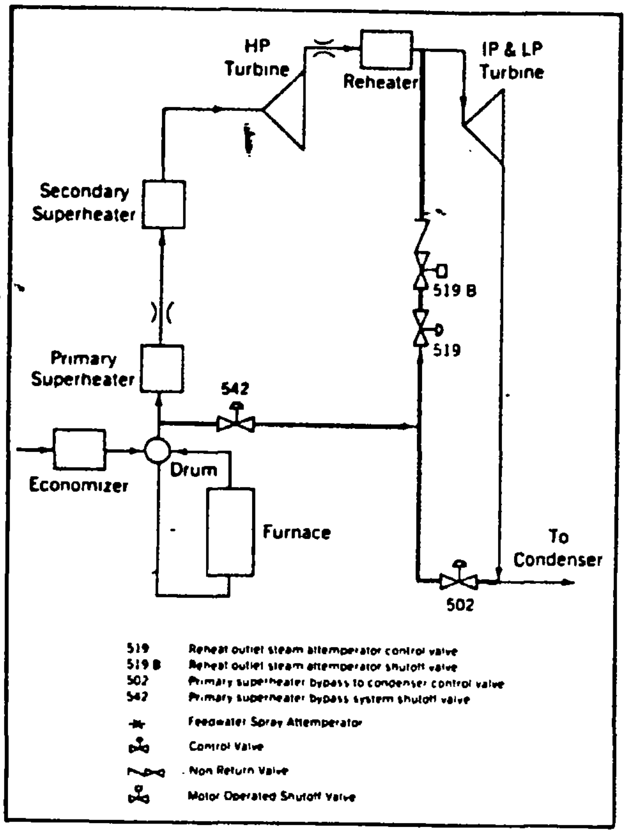

Figure 11 Partial bypass system.

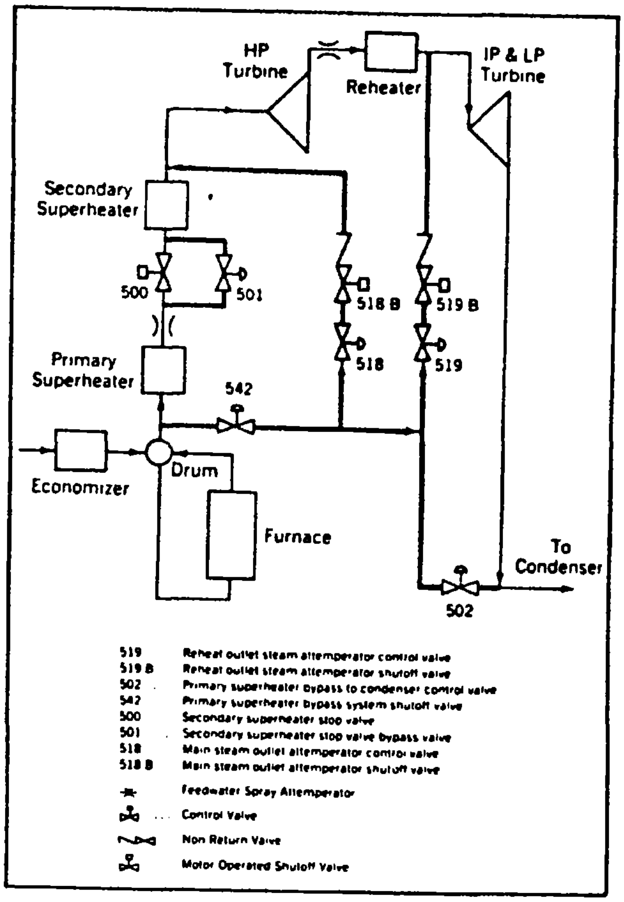

Figure 12 Full bypass system.

from both the furnace walls and convection surfaces (see Figure 15).

The initial complement of blowers will include 54 wall blowers, 52 long retractable sootblowers and 16 half-track sootblowers. Wall boxes will also be installed initially for 75 future wall blowers, 40 future long retractable sootblowers and 12 future half-track sootblowers. These wall boxes could be used for either additional sootblowers or a rearrangement of the initial sootblowers, depending upon the exact fuel being burned and its slagging/fouling characteristics.

Sootblowers are also being furnished for the four air heaters.

Steam source for furnace and convection pass sootblowers will be from an intermediate superheater header. The steam source for the air heater sootblowers will be from the secondary superheater outlet header.

Comparison to other large coal-fired boilers

The industry accepts major gas side and water/steam side design parameters as indication of the conservatism of a particular boiler design. It is useful to review these parameters in relationship to the manufacturer's experience.

Water side design: In order to provide an adequate margin of safety for cooling of the furnace wall tubes, the maintenance of a conservatively high minimum departure from nucleate boiling ratio (DNBR) was set as a primary design objective by B&W. DNB ratio is defined as follows:

$$\text{DNBR} = \frac{\text{Minimum heat flux required for DNB (Btu/ft}^2\text{/hr)}}{\text{Maximum upset heat flux (Btu/ft}^2\text{/hr)}}$$

A minimum DNBR of 2 was established as the design objective. As a comparison, a nuclear reactor has a DNBR of 1.2. The minimum DNBR for B&W furnace tubes occurs just above the top row of burners at the point of maximum upset heat flux. Therefore, at the steam qualities being encountered along the length of the furnace tubes, the predicted maximum upset heat flux (caused by

Table 5 Utah coal and ash analysis

	Performance coal	Range
Proximate analysis		
Moisture	8.3	7.4 - 9.4
Volatile matter %	37.1	35.0 - 40.0
Fixed carbon %	40.6	38.0 - 44.0
Ash %	14.0	8.0 - 16.0
Higher heating value, Btu/lb	11,010	10,500 - 12,100
Grindability	48	43 - 53
Ash analysis %		
SiO_2	58.8	49.3 - 61.0
Al_2O_3	13.5	10.7 - 16.8
Fe_2O_3	5.9	3.9 - 7.9
TiO_2	0.7	0.5 - 0.9
CaO	9.3	3.9 - 14.6
MgO	2.0	0.8 - 3.0
Na_2O	1.6	0.6 - 3.0
K_2O	0.9	0.6 - 1.3
SO_3	5.9	2.9 - 8.9
P_2O_5	0.3	0.1 - 1.0
Undetermined	1.1	0.3 - 0.3
Ash fusion temperatures		
Reducing: Initial deformation	2180	2075 - 2300
Softening	2215	2095 - 2340
Hemispherical	2245	2115 - 2380
Fluid	2330	2190 - 2470
Oxidizing: Initial deformation	2240	2130 - 2355
Softening	2300	2135 - 2455
Hemispherical	2325	2200 - 2450
Fluid	2410	2255 - 2570

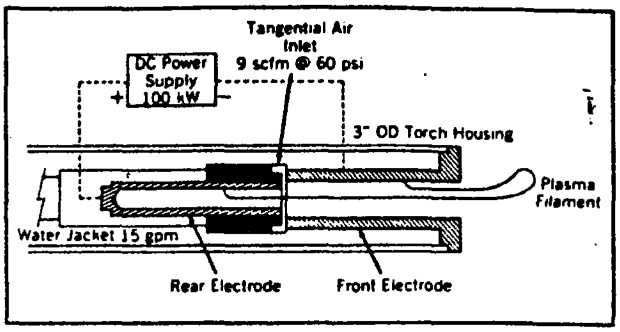

Figure 14 Plasma torch ignitor.

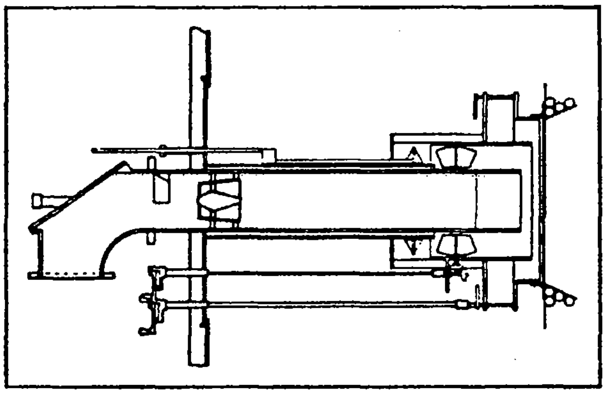

Figure 13 Dual register burner.

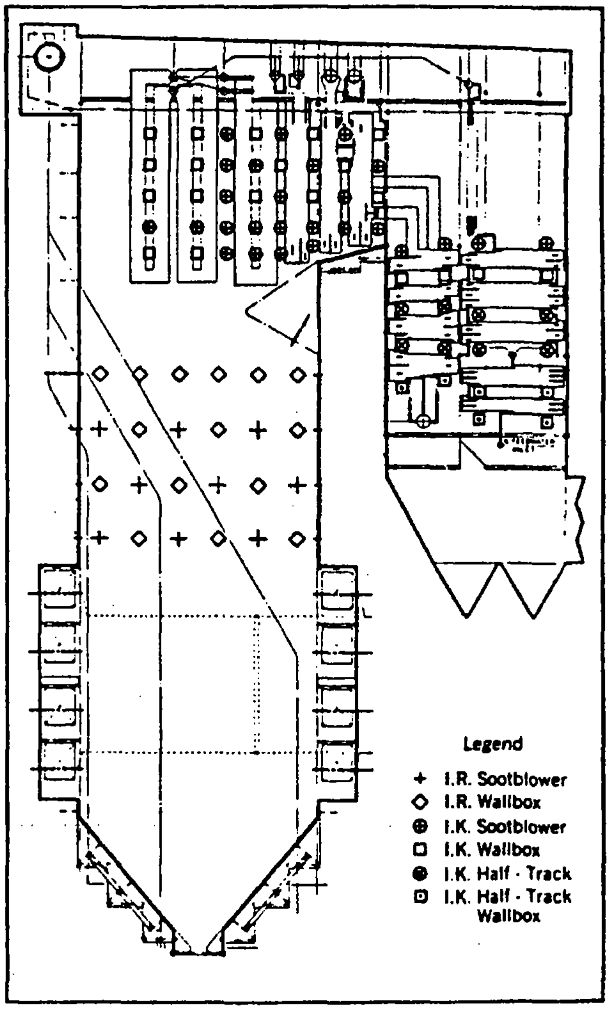

Figure 15 Sootblower installations.

overfiring or other local conditions) would not be greater than ½ the heat flux required to cause DNB. A typical DNB curve is shown on Figure 16. As can be seen from the cure, the minimum DNBR for smooth tubes designed for a mass flow of 800,000 lbs/ft²/hr occurs just above the top burner level at point B where the DNBR approaches 1. By contrast, the minimum DNBR for the IPP design with ribbed tubes at this same mass flow and same elevation in the furnace is greater than 2. This design philosophy, used in many units, has resulted in reliable furnace circuitry. The average minimum mass velocity for recent B&W designs is between 800,000 and 900,000 lbs/ft²/hr. Although B&W units have been tested for minimum circulation mass flows below 600,000 lbs/ft²/hr and for circulation ratios below 2.5 for extended periods, excellent historical experience is available for circulation ratios of 3 and above, with minimum average tube mass velocities of approximately 800,000 lbs/ft²/hr.

Gas side design: As mentioned previously, the major specified design parameters included are:

1. Heat release per square foot of furnace plan area of 1.6 million Btu/ft²/hr.

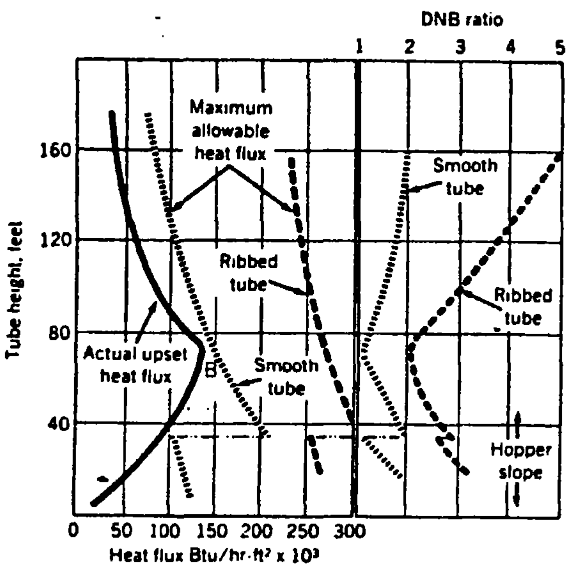

Figure 16 DNB curve.

2. Gas side design maximum velocity of 55 fps.
3. Gas temperature entering close-spaced pendant surface must be less than 1900 F HVT.
4. Minimum distance from top burner to platen of 80 feet.

Each of these criteria are conservative relative to B&W's experience. A listing of operating B&W units (Table 6), having large open furnace of the size employed for this project, includes sixteen units with average plan area heat release rate of 1,875,000 Btu/ft²/hr, gas side maximum gas velocity of 65 fps and FEGT of 2195 F HVT. Average unit size is 975 MW.

These large boilers have performed very well, turning in a cumulative boiler availability of over 90% for 97 unit years of operation. This is well in excess of the industry average of 84.7%, as reported by the operating utilities to the North American Electric Reliability Council (NERC). The IPP boiler design represents a more conservative application of these design criteria than those large boilers which were designed in the early '70s.

Figures 17 through 20 show the relative position of the IPP units compared to other recent B&W contracts for these various gas side design parameters of burner zone release rate, heat input to furnace plan, gas velocity and gas temperature entering the pendant superheater. It can be seen that the IPP units rank with the most conservative B&W units designed for bituminous coals. This conservative approach was a decision which the Intermountain Project expects will provide benefits in improved equipment reliability.

Availability improvement program

The customer, his A/E (Black & Veatch) and the Babcock & Wilcox Company have agreed to mutually support and participate in an Availability Improvement Program (AIP) in

Table 6 Operating large open-furnace boilers

		Plan area (ft²)	Plan area heat release Btu/ft²-hr × 10³	FEGT/ spacing	Maximum gas velocity fps
Detroit Edison	Monroe 1-4	3645	1929	2250/18"	71
Ohio Power	Amos 3	5661	2108	2225/18"	64.7
Duke Power	Belews Creek 1-2	4590	2126	2180/18"	75
AEP	Gavins 1-2	5661	2108	2225/18"	64.7
	Mountaineer 1	5661	2215	2220/18"	68.6
Texas Utilities	Monticello 3	5130	1538	2000/24"	58.6
Kansas City P&L	La Cygne 2	4182	1554	2130/24"	59
	Iatan 1				
Iowa P&L	Council Bluffs	3927	1775	2190/18"	57
Houston L&P	Parish 5-6	4182	1554	2220/24"	59

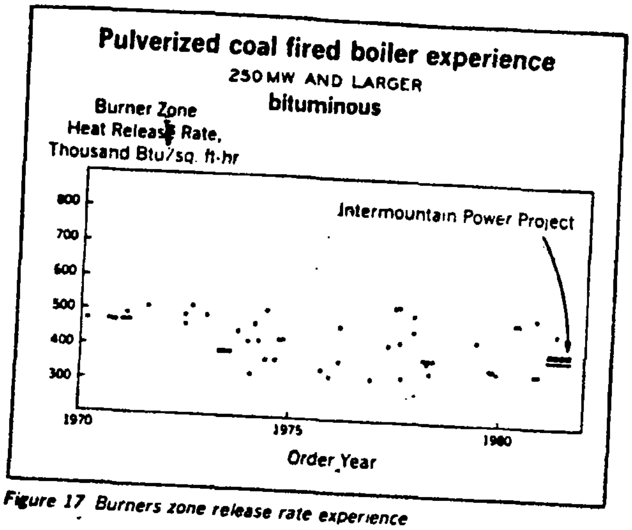

Figure 17 Burners zone release rate experience

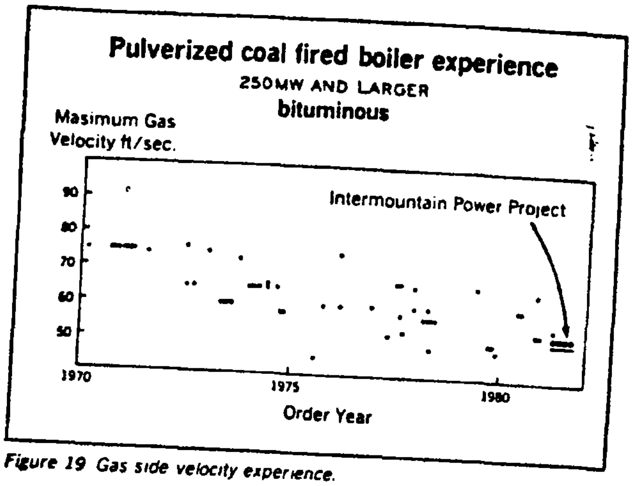

Figure 19 Gas side velocity experience.

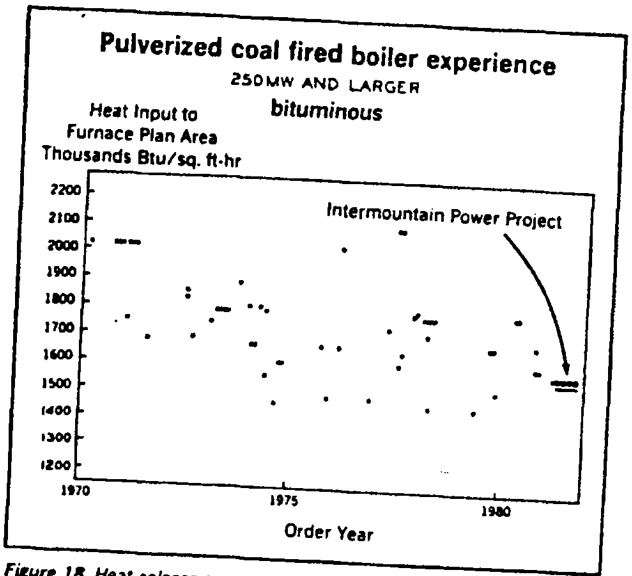

Figure 18 Heat release per square foot of furnace plan area experience.

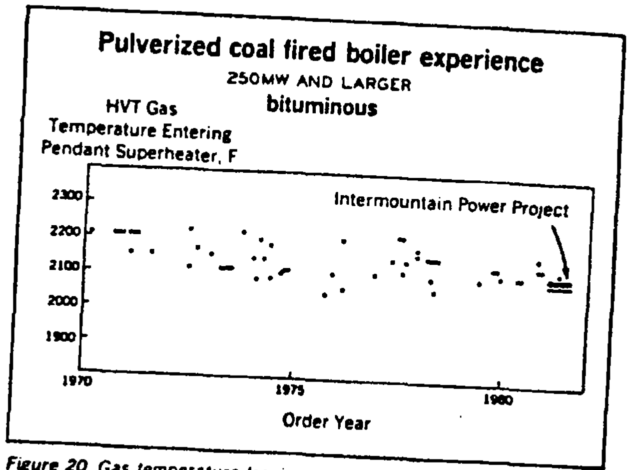

Figure 20 Gas temperature leaving the furnace experience.

further efforts to achieve high availability.

The purpose of the AIP is to ensure that the IPP boilers and interfacing plant equipment are designed, manufactured, erected and operated to achieve maximum operating availability. This purpose will be achieved through a formal structured task force committee.

Aside from monitoring the progress and performance of the IPP units, there are 17 pre-selected Babcock & Wilcox Co. units, installed at ten different locations, having certain similarities to the IPP units which will be monitored to determine root causes of unit outages or reduced capability. A determination would then be made as to whether or not the IPP units would be subject to the same problems and, if so, what can be done to prevent them on the IPP units.

The reviews will go beyond the terminals of the boiler scope to include all interfacing plant equipment such as feedwater systems, fuel preparation, ash handling, controls, etc.

The goals of the IPP will be implemented through an availability task force. The task force will meet periodically to review the operating history of the reference plants; review items that have arisen on the IPP units; and to make recommendations for the improvement of availability in the areas of design, fabrication construction and operation. The composition of this organization and its membership is shown on Figure 21:

Similar programs are being established by IPP with other major plant equipment suppliers.

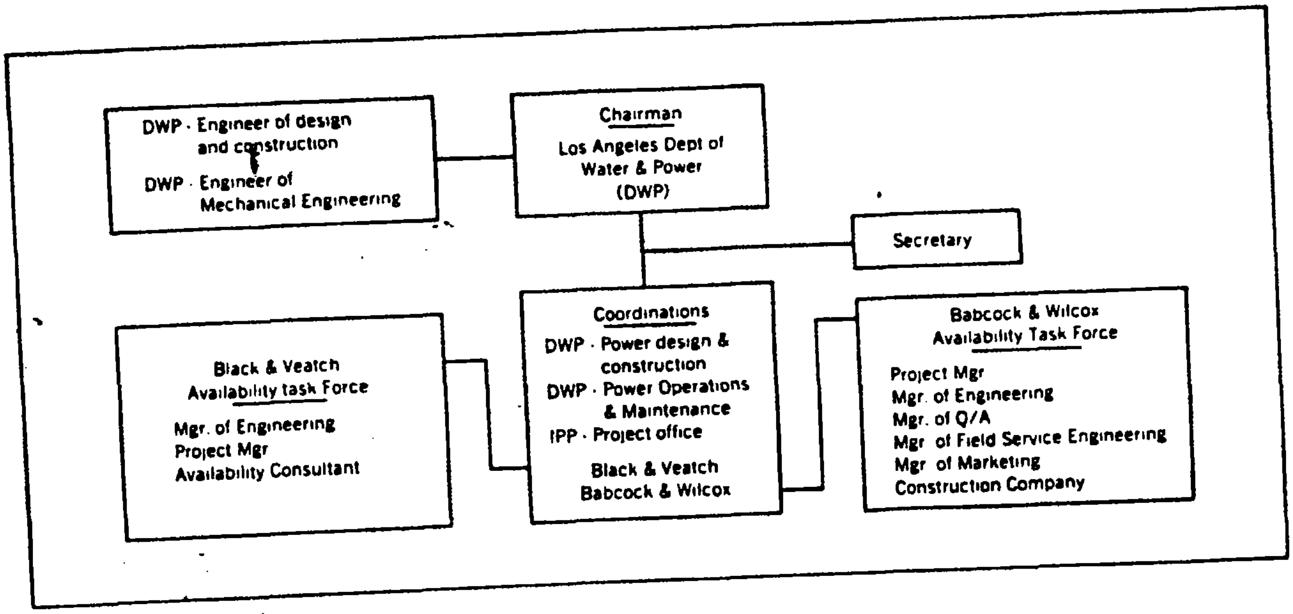

Figure 21 Availability task force.

Conclusion

This paper has addressed major criteria that were specified for the steam generators and an evaluation of design conducted by the Intermountain Power Project and how these factors were treated in the design of the boiler units by the Babcock & Wilcox Company. We have also reviewed the concept of an availability improvement program geared to further improve the design, manufacturing and erection of these units. The Project is confident that these steps will achieve the desired goals and we look forward to reporting the support of this project after these units are placed into operation.

ATTACHMENT 6

UDI

Utility Data Institute, Inc.

Christopher A. E. Bergesen, Manager, Business Development

June 30, 1983

Mr. James Anthony
Intermountain Power Project
111 North Hope Street
P.O. Box 111, Room 931
Los Angeles, California 90051

Dear Mr. Anthony:

This letter and the attached table constitute Utility Data Institute's (UDI) report on its survey conducted to establish the emission limitations for nitrogen oxides (NOX) contained in the PSD permits that have been issued for bituminous, coal-fired steam-electric generating plants. The survey covers all power plants that received PSD permits through early June 1983. To get the information reported in the attached table, UDI reviewed numerous PSD permits and contacted USEPA regional offices, states, and utilities.

Please contact me with any questions or comments.

Very truly yours,

Chris Berg

BACT Emission Limitations
for Nitrogen Oxides
for PSD-Permitted, Bituminous Coal-Fired Power Plants
by EPA Region*

Utility Data Institute

REGION II

Operator	Plant/Unit	Date of PSD Permit	NOX
NEW YORK			
New York State Electric & Gas	Somerset 1	810629	0.60

REGION III

Operator	Plant/Unit	Date of PSD Permit	NOX
DELAWARE			
Delmarva Power & Light Co.	Indian River 4	761029	0.70
MARYLAND			
Delmarva Power & Light Co.	Vienna 9	810930	0.60
PENNSYLVANIA			
Pennsylvania Electric Co.	Coho 1	810818	0.60

*EPA Region I has not issued PSD permits for coal-fired steam electric plants.

REGION IV

Operator	Plant/Unit	Date of PSD Permit	NOX
ALABAMA			
Alabama Electric Coop.	Choctaw 1-4	810224	0.6
Alabama Power Co.	Miller 4	780330	0.70
FLORIDA			
Jacksonville Electric Auth.	St. Johns River 1&2	820303	0.60
Lakeland Light & Water Dept.	McIntosh 3*	781228	0.70
Orlando Utilities Comm.	Stanton 1&2		0.60
Seminole Electric Coop.	Seminole 1&2*	790809	0.60
Tampa Electric Co.	Big Bend 4	811015	0.60
KENTUCKY			
Big Rivers Electric Corp.	DB Wilson 1&2	810311	0.60
	Green 1&2	770728	0.70
Cincinnati Gas & Electric Co.	East Bend 1	780620	0.70
	East Bend 2	760901	0.70
East Kentucky Power Coop.	HL Spurlock 2	760921	0.70
	JK Smith 1&2	800821	0.60
Kentucky Power Co.	Lewis County 1&2	800424	0.60
Kentucky Utilities Co.	Ghent 3&4	771107	ND
	Hancock 1&2	820415	0.60

*Limits for coal-firing

Operator	Plant/Unit	Date of PSD Permit	NOX
Louisville Gas & Electric	Trimble County 1-4	780118	ND
NORTH CAROLINA			
Carolina Power & Light Co.	Mayo 1&2	771028	0.70
SOUTH CAROLINA			
South Carolina Electric & Gas	Cope 1&2	790801	0.60
	Wateree 3	790904	0.60
South Carolina Public Service	Cross 1&2	790711	0.60
	Cross 3	811203	0.60
	Winyah 3&4	780228	0.70
	REGION V		
ILLINOIS			
Central Illinois Light Co.	Duck Creek 2&3	800815	0.60
Soyland Elec. Power Coop.	Soyland 1		0.60
INDIANA			
Indiana State REC	Merom 1&2	790628	0.70
Indianapolis Power & Light Co.	Patriot 1-3	791214	0.60
	Petersburg 4	780221	0.70
Northern Indiana Public Service	RM Schahfer 17&18	801002	0.60
Public Service Indiana	Gibson 5	780317	0.70
Southern Indiana Gas & Electric	AB Brown 2	790222	0.60

Operator	Plant/Unit	Date of PSD Permit	NOX
MICHIGAN			
Grand Haven Board of Light & Power	JB Sims 3	800318	0.60
Michigan South Central Power	Michigan Project 1	800516	0.60
	REGION VI		
LOUISIANA			
Louisiana Power & Light	Wilton 1&2		0.60
	REGION VII		
IOWA			
Muscatine Power & Water	Muscatine 9	800124	0.60
MISSOURI			
Associated Electric Coop.	Thomas Hill 3	780206	0.70
Sikeston Board of Municipal Utilities	Sikeston 1	770714	ND
	REGION VIII		
UTAH			
Deseret G&T Coop.	Moon Lake 1&2	810204	0.55
Los Angeles Department of Water & Power	Intermountain 1-4	800608	0.55
Utah Power & Light Co.	Hunter 3&4	800602	0.55

REGION IX

Operator	Plant/Unit	Date of PSD Permit	NOX
ARIZONA			
Arizona Public Service Co.	Cholla 5	780215	0.70
	REGION X		
WASHINGTON			
Washington Water Power Co.	Creston 1-4		0.60

Notes:

ND = Not available or no data.

Date of PSD Permit = Date Final PSD Decision Made (Y/M/D); there is no date listed for permits issued after May 1982.

ATTACHMENT 7

BLACK & VEATCH

MEMORANDUM

JUL 1 1983

Intermountain Power Project
Intermountain Generating Station
90 and 95 Per Cent SO_2 Removal Costs
Per Ton of SO_2 Removed

B&V Project 9255
B&V File 14.0200
32.0400
41.1007
July 1, 1983

To: R. L. Nelson

From: D. O. Swenson

An analysis of the costs of SO_2 removal for Units 1 and 2 at the Intermountain Generating Station has been performed. The costs of flue gas desulfurization (FGD) per ton of SO_2 removed for the Intermountain Generating Station are shown on Table 1 for 90 per cent and 95 per cent SO_2 removal. These costs are presented in total levelized annual 1986 dollars per ton of SO_2 removed and incremental levelized annual 1986 dollars per additional ton of SO_2 removed by retrofitting for 95 per cent design SO_2 removal prior to commercial operation. The total levelized annual costs is the sum of the total capital cost and the capitalized operating costs multiplied by the levelized annual fixed charge rate. Total capital costs for the 90 per cent SO_2 removal system in this table were taken from the Air Quality Control System Contract Estimate Summary, March 18, 1983. The equipment in this capital cost estimate includes limestone receiving and storage equipment, limestone additive preparation equipment, flue gas desulfurization equipment (including flue gas reheat), FGD waste separation and storage equipment, FGD ductwork and dampers, FGD piping and valves, FGD electrical and control equipment and FGD structures, including foundations and support steel. The total FGD system operating costs were calculated with an Air Quality Control System cost estimating program using the Intermountain Generating Station

JUL 1 1983

operating conditions and fuel data. The equivalent differential capital cost with a 95 per cent SO_2 removal system retrofitted prior to commercial operation was taken from Table 4-2 of the June 17, 1983 special report, "Cost Analysis of Various NO_x and SO_2 Control Technologies for the Intermountain Power Project". The incremental levelized annual cost is the equivalent differential capital cost for 95 per cent SO_2 removal multiplied by the levelized annual fixed charge rate.

dlw
Attachment

TABLE 1. COSTS PER TON OF SO_2 REMOVED FOR 90 AND 95 PER CENT SO_2 REMOVAL (INCLUDING CAPITAL AND ANNUAL COSTS)[1]

	Unit 1 \$/ton	Unit 2 \$/ton	Total \$/ton
Total Flue Gas Desulfurization Cost Per Ton of SO_2 Removed			
90% Removal (23.2 thousand tons SO_2 removed per year per unit)	1,500	1,000	1,260
95% Removal (24.5 thousand tons SO_2 removed per year per unit)[2]	3,980[3]	3,780[3]	3,880[3]
Incremental Flue Gas Desulfurization Cost Per Ton of Additional SO_2 Removed			
95% Removal (1.3 thousand tons additional SO_2 removed per year per unit)[2]	48,200[3]	53,000[3]	50,600[3]

1. Costs are in levelized annual 1986 dollars.
2. Retrofit for 95 per cent design SO_2 removal prior to commerical operation.
3. Includes replacement power cost for 18 month delay.

DATE DEC 22 1978

SUBJECT: BACT Information for Coal-fired Power Plants

FROM: Walter C. Barber, Director
Office of Air Quality Planning and Standards (MD-10)

TO: Director, Air & Hazardous Materials Division, Regions I-X

Currently, there seems to be some confusion regarding how much information is required in order to make BACT determinations for power plants. Such confusion has created situations where one Region may have conditionally approved a power plant's construction plans while another would not. This memo is intended to provide an example of the type and amount of information required from power plant applicants in order to determine whether the source is applying BACT.

Under the new PSD regulations, BACT is necessarily decided on a case-by-case basis after weighing relevant socio-economic costs and environmental impacts. Consequently, information must now be submitted by a PSD source describing its plans for control equipment in sufficient detail so as to define the plant-specific BACT limit. As indicated in separate guidance for making case-by-case BACT determinations, the utility is also required to demonstrate that the proposed controls are not less stringent than the applicable NSPS and that more stringent control alternatives are not appropriate.

While the new PSD regulations require a reasonable degree of assurance that the source can and will install BACT, they also permit the Agency to establish a system for initial BACT review followed by a more detailed control equipment analysis. While such a system does not relieve the source from its responsibility to demonstrate to the Agency that it is applying BACT, it does act to streamline the review process and minimize the delays incurred by power plants which cannot supply ultimate equipment designs and blueprints at the time that a permit to construct is secured. This system will also provide the utility with sufficient flexibility to take advantage of expected improvements in control technology.

The key question then becomes how much information is necessary to establish the BACT limit during the initial preconstruction review. In general the information should include the preliminary engineering and plant design criteria which will constitute the basis for soliciting and reviewing vendor proposals for control equipment. In addition, an example should be included which specifies how the preliminary design criteria would be applied to the particular plant in question or to a similar facility where the design has been completed and the exact detailed specifications are available. Where a utility has not settled on a single control system, it may submit alternatives for review.

Attachment A is provided as an example of the type of information which can be used both to define a specific BACT emission limit and to assess whether the plant can be reasonably expected to meet this limit. Power plants can be permitted when this initial information confirms that BACT will be employed and that the applicable ambient constraints will be met. This approach must be conditioned on the company's later submission of final detailed engineering design specifications prior to commencement of construction of the control equipment. While the final engineering design and vendor specifications will vary from the preliminary information, the utility must show it to be equivalent in performance and reliability established as BACT in the initial determination. These variations may include basic changes in equipment design such as a shift from an ESP to a baghouse, a change from a lime/limestone scrubber to a regenerable scrubbing system or a change in the design approach to insuring reliability.

All of the information outlined in Attachment A may not be available and is not required in all instances. The reviewing authority should seek only those data elements which are necessary to support air engineering judgment that the proposed system will perform reliably at the specified emission rates.

Since the submission of the final engineering design specifications is a condition of the permit, this would not constitute a reopening of the permit process, and I do not see the need for an opportunity for public comment on this material. However, I do recommend that the approval notice contain the location and approximate time period in which this final design information would be available.

The above guidance represents some change for several Regions. Therefore, I am requesting that during 1979 you submit to OAQPS your BACT determinations for SO_2 from coal-fired power plants (together with the applicable BACT information identified in Attachment A) for review prior to your preliminary determination. If some of your States are making these BACT determinations, I ask that you send us the appropriate BACT information before they make their final determination. The above information should be sent to Mike Trutna (629-5497) who will coordinate OAQPS's activities regarding these determinations in the near future. Suggestions on additions or modifications to this guidance also should be addressed to Mr. Trutna.

Attachments

cc: Director, Enforcement Divisions, Region I-X
D. Hawkins
R. Rhoads
M. James
E. Reich
E. Tuerk

PRELIMINARY BACT INFORMATION*

A. GENERAL INFORMATION

1.a. Name of Power Plant and Parent Company ______________________

b. Name, address, phone no. of company contact ______________________

____

2. Location of Source

a. City ______________________ b. State ______________________

B. STEAM GENERATOR DATA

1. Type of boiler (manufacturer, if known)
2. Size of boiler (heat input 10^6 Btu/hr)

C. FUEL DATA

Provide long term averages and ranges for specified short term and long term averaging periods for the following (1-6):

1. Primary fuel (coal or oil)
2. Start up fuel
3. Alternate fuels
4. Brief description of what fuels will be fired including estimated percentage heat input
5. Solid fuel data (all solid fuels to be fired)
   a. Ultimate analysis (as burned) % by weight sulfur also include chlorine, ash, moisture and gross heating value (Btu/lb)
   b. Estimated resistivity of particulate as a function of gas temperature (if known)
   c. Estimated ash analysis (% by weight - dry)
6. Particle size analysis for ash
7. Liquid fuel data (all liquid fuels)
   a. Type and grade
   b. Density (lb/gallon)
   c. Gross heating value (Btu/gallon)
   d. Ash content (percent by weight)
   e. Sulfur content (percent by weight)
   f. Nitrogen content (percent by weight)
   g. Moisture (percent by weight)
   h. Will additives by used? If so, furnish data on chemical composition and approximate quantitites (percentage of total fuel to be used).
8. Is a contract signed for the coal? If no contract is signed, we would need the information for questions 1-6 for all coals that are being contemplated for usage and percentage usage where coals are to be blended.

*Note that not all information may be available in all cases. Information requirements should be adjusted as appropriate to fit the circumstances of the applicant at time of permit application.

D. PRECIPITATOR DATA

Part I - Preliminary design or design criteria

1. Design emission rate (lbs/mBTU) for particulate matter (before and after proposed controls)

2. Total gas flow from steam generator at full load and at ESP operating temperature (ACFM)

3. ESP operating temperature (±F) range

4. Number of separate ESP modules under consideration

5. Approximate specific collection area (SPA)

6. Number of separate electrical sections for each module under consideration.

7. Type of power control and instrumentation

8. Estimated linear velocity of gas through each module at full load (actual feet/sec) or range of acceptable velocities

9. Briefly describe techniques used to ensure uniform linear velocity within ESP.

10. Nature and terms of performance guarantee

11. Briefly describe system used to remove and convey collected ash to final disposal.

Part II - Reference plant example

1. General flow diagram for the precipitator

2. Provide design criteria or preliminary engineering data for the major elements of the ESP for the particular plant under consideration or a similar plant where the major elements have been designed and detailed specification are available.

E. BAGHOUSE DATA

Part I - Preliminary design or design criteria

1. Design emission rate (lb/mmBtu) for particulate matter (before and after proposed controls)

2. Estimated total gas flow from steam generator at full load and at baghouse operation temperature (ACFM)

3. Baghouse operation temperature (±F) range

4. Number of separate baghouses

5. Number of isolated compartments per baghouse

6. Design criteria for air to cloth ratio or range of acceptable ratios (Cloth area divided by total ACFM)

7. Cloth description

8. Type of bag cleaning under consideration and subsequent cleaning controls

9. Strategy for detecting and replacing faulty bags

10. Description of ash handling and disposal system

11. Nature and terms of performance guarantee

Part II - Reference plant example

1. General flow diagram for the baghouse

2. Provide design criteria or preliminary engineering data for the major elements of the baghouse for the particular plant under consideration or a similar plant where the above elements have been designed and detailed specifications are available.

F. SULFUR DIOXIDE SCRUBBER DATA

Part I - Preliminary design or design criteria

1. Design emission rate (lb/mm Btu) of SO_2 (before and after proposed controls)
2. Design data or criteria for the scrubber modules to include:
   - scrubber type (TCS, spray tower, etc.)
   - absorbent type
   - possible scrubber liquor additives (e.g., mg)
   - prescrubber design criteria, or acceptable ranges for l/g, inlet and outlet chloride, etc.
   - design criteria for acceptable ranges for inlet and oulet gas flow and temperature and volume percent H_2O, O_2, and SO_2
   - specific design criteria or acceptable ranges for liquid/gas ratio
   - estimated scrubber gas velocity
   - design criteria or acceptable range for scrubber inlet and outlet pH
   - design criteria or acceptable range of pressure drop across the scrubber (inches of H_2O)

3. *For turbulent contact absorber (TCA) also supply:*
   - design criteria or acceptable ranges for diameter of spheres
   - design criteria or acceptable ranges for the height of sphere in TCA
   - design criteria or acceptable ranges for number of grids or screens in TCA

4. Indicate total number of scrubber modules and number of spare modules during maximum boiler loading.

5. What special precautions will be taken with module internals and other components (pumps, mist eliminators, fans, etc.) to ensure that corrosion, scaling, and plugging does not cause failure of the systemu

6. What special precautions will be taken with the control systems, e.g., spare probes, probe site location, probe sheaths, backup instrumentation to ensure that failure will not lead to excess emissions or fouling of components via scaling?

7. How will other key variables, such as process stochiometry, liquid to gas ratios (l/g), etc., be monitored to ensure good operations?

8. Indicate which key components of the scrubber will be spared, e.g., pumps, fans, nozzles, etc.

9. Location and mechanism of reheat, auxiliary fuel requirements, and percentage of exhaust gas reheated. If reheat will not be performed, indicate what measures are being taken to eliminate stack corrosion or provide data to verify that stack corrosion will not be a problem area.

10. Outline routine maintenance and inspection procedures for the scrubber system hardware to ensure continuous and reliable scrubber performance.

11. Describe the general design standard for the material to be used and type of mist eliminator system and describe the techniques under consideration to guarantee uniform gas distribution across the mist eliminator and to the scrubber modules.

12. Nature and terms of performance guarantees

Part II - Reference plant example

1. General flow diagram of the scrubber system including mix tanks prequench section, scrubber modules, mist eliminator and reheat. General design standards for materials to be used to construct above elements.

2. Provide design criteria for the major scrubber and system components (e.g., pumps, tanks, alkali handling systems, etc.) for the particular plant under consideration or a similar plant where the above items have been already designed and detailed specifications are available.

G. Other Sulfur control methods*

I. Description of control method

II. Amount of sulfur removal credit

*These "other sulfur control methods" are those designed to augment SO_2 scrubbers in order to achieve a given rate of SO_2 removal. An example of such a method would be coal cleaning.

Scott M. Matheson
Governor

James O. Mason, M.D., Dr.P.H.
Executive Director
801-533-6111

DIVISIONS

Community Health Services
Environmental Health
Family Health Services
Health Care Financing

OFFICES

Administrative Services
Community Health Nursing
Management Planning
Medical Examiner
State Health Laboratory

Attachment 5

STATE OF UTAH
DEPARTMENT OF HEALTH
DIVISION OF ENVIRONMENTAL HEALTH
150 West North Temple, P.O. Box 2500, Salt Lake City, Utah 84110-2500

Marv H. Maxell, Ph.D., Acting Director
Room 474 801-533-6121

UTAH STATE DEPARTMENT OF HEALTH
UTAH AIR CONSERVATION COMMITTEE MEETING
MAY 23, 1983 - 1:30 P.M.
AUDITORIUM, WILDLIFE RESOURCES BUILDING
1596 WEST NORTH TEMPLE, SALT LAKE CITY, UTAH

TENTATIVE AGENDA

I. Call to Order

II. Date of Next Meeting

III. Minutes of Subcommittee Meeting, April 15, 1983
Minutes of Regular Committee Meeting, April 15, 1983

IV. Variance Requests
Initial
- Provo City Power
- U. S. Steel

V. Appointment of Hearing Officers

VI. Update on Anti-Tampering Program

VII. Update on EPA SIP Actions

VIII. Other Business

Attachment 6

Scott M. Matheson
Governor

STATE OF UTAH
DEPARTMENT OF HEALTH
DIVISION OF ENVIRONMENTAL HEALTH
150 West North Temple, P.O. Box 2500, Salt Lake City, Utah 84110-2500

James O. Mason, M.D., Dr.P.H.
Executive Director
801-533-6111

DIVISIONS

Community Health Services
Environmental Health
Family Health Services
Health Care Financing

OFFICES

Administrative Services
Community Health Nursing
Management Planning
Medical Examiner
State Health Laboratory

Marv H. Maxell, Ph.D., Acting Director
Room 474 801-533-6121

May 11, 1983

MEMORANDUM TO: Utah Air Conservation Committee

FROM: Brent C. Bradford, Executive Secretary

SUBJECT: Air Conservation Committee Meeting, May 23, 1983

A regular meeting of the Air Conservation Committee has been scheduled for May 23, 1983, at 1:30 P.M. in the Wildlife Resources Auditorium, 1596 West North Temple, Salt Lake City.

Attached is a tentative agenda for the meeting.

The hearings for the SIP and regulation changes adopted by the Committee at the April 15, 1983 meeting have been scheduled for June 2, 1983. Seven hearings will be held simultaneously that day in each Association of Government area in the state.

You will find included in the mailing this month a good deal of material related to acid rain impacts, NOx emissions, etc. This information has been provided by Sherman Young. Mr. Young is interested in providing the Committee information related to acid rain as input to any decision that may be made relative to IPP.

The staff has reviewed the information submitted by IPP at the last meeting and a summary memo of that information is included as required by the Committee.

You will note that the IPP issue is not on the agenda for the May meeting. The staff is currently gathering additional information necessary to make a BACT determination on the IPP application for a modified source. When the preliminary BACT determination has been made, we will then have something concrete to discuss.

If you have any questions, please contact me.

BCB/ads
2957

Attachment 7

Scott M. Matheson
Governor

STATE OF UTAH
DEPARTMENT OF HEALTH
DIVISION OF ENVIRONMENTAL HEALTH

150 West North Temple, P.O. Box 2500, Salt Lake City, Utah 84110-2500

Marv H. Maxell, Ph.D., Acting Director
Room 474 801-533-6121

James O. Mason, M.D., Dr.P.H.
Executive Director
801-533-6111

DIVISIONS
Community Health Services
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Medical Examiner
State Health Laboratory

May 13, 1983
533-6108

MEMORANDUM TO: Utah Air Conservation Committee Members

FROM: Brent C. Bradford, Executive Secretary, Utah Air Conservation Committee

SUBJECT: Summary of the of IPP Document Dated April 14, 1983, Submitted to the Committee on April 15, 1983

IPP's submittal contains two enclosures put together by consulting firms. The first comments on problems with the California Air Resources Board (CARB) guidelines for control of emissions from coal fired power plants. The second report deals with the feasibility and cost of placing selective catalytic reduction (SCR) and 95% SO_2 removal equipment on the IPP plant.

IPP states that by submitting this data, they do not concede the CARB guidelines in any way apply to IPP. IPP also states their opinion that under the Utah Air Conservation Regulations (UACR), the plant is not subject to either major modification review nor any further control technology review. IPP goes on to point out that the CARB guidelines are not law in California. IPP concluded by stating the CARB guidelines have not been demonstrated to be attainable, and the cost to implement the CARB proposed control technology would seriously threaten the economic feasibility of the project.

Summary of Enclosure 1
"Review of the California Air Resource Board Report Titled Proposed Guidelines for the Control of Emissions from Coal Fired Power Plants" by Stearns-Roger Engineering

Most of the Stearns-Roger comments deal with the technical problems of the CARB guidelines and are only indirectly linked to the feasibility of the pollution control equipment. Those comments are as follows:

A. Continuous emissions monitors (CEM's) currently available will not reliably measure the low pollutant concentrations required by CARB. The CARB guideline requirement that particulate emissions and opacity be correlated, and that this correlation be used to determine continuous compliance with the particulate standard cannot be done at such low concentrations.

B. The limitation for particulate matter is stated in grains/ACF rather than lb/10^6BTU, and the locations in the gas train where particulate matter and SO_2 are to be measured are not adequately specified. It is also not clear whether condensibles are to be counted as particulate matter.

C. CARB requires that the NO_X and SO_2 limitation be met on a three hour running average basis verses the 30 day average required by NSPS. The extra stringecy required by the three hour averaging time and its associated costs were not considered by CARB.

D. No provisions were made for upset and malfunction.

The major points in the report which address the feasibility of the control technolgy are:

A. Particulate. Only about 50% of existing fabric filter installations meet the .005 grain/ACF emission limitation, and the performance of fabric filters in terms of collection efficiency has yet to be characterized by any relationship involving fabric filter size or other parameters. Therefore, designing a baghouse to meet the lower limitation "requires the application of a science which does not currently exist."

After stating that the limitation could not be met, Stearns-Roger estimated the additional cost to go from NSPS limit to the CARB guidelines limit as the addition of extra filter compartments for increased maintenance and installation of opacity meters for detection of leaking bags.

B. Sulfur Dioxide. CARB should have calculated the costs of going from 70% (NSPS) to 95% removal rather than 90% to 95%. Combined with the three hour averaging period, 95% is pushing SO_2 scrubbers beyond their capability.

C. Oxides of Nitrogen. Information and data upon which to design a SCR system is limited to a Japanese demonstration plant (Takahara) and two U.S. pilot plants. These data are not adequate to design for the specifics of the CARB guidelines. Many problems were encountered in scaling up from pilot plants to the 100 KW_X. Takahara demonstration. Specific problems were a required increase in catalyst to reduce ammonia slip and blockage of the catalyst with dust.

CARB misinterpreted some cost reports and ignored the fact the spent catalyst may have to be disposed of as a hazardous waste. This resulted in an under estimate of costs.

Summary of Enclosure 2
"Intermountain Generating Station 95% SO_2 Removal and Selective Catalytic Reduction of NO_X" To R. L. Nelson from R.W. Dutton

This memo gives a brief review of how SCR works and what would be required to install the equipment at IPP. If a decision to put SCR on IPP was made on June 1, 1983, an 18 month delay to the project would result. The memo then reviews the SO_2 scrubber stating the present design is for 90% removal on a 30 day average, and that this level is the upper limit which scrubbers are able to achieve on a continuous basis. Removal efficiency above 90% on a continuous basis has not been demonstrated. The major obstacle to higher efficiency on a continuous basis is the inability to overscrub to make up for periods of reduced efficiency due to component failure, etc. In order to estimate the cost for 95% removal, the memo uses a SO_2 scrubber designed with nine modules; five on line necessary to meet 95% removal, two on standby, and two under maintenance. (The present design has six modules; four on line to meet 90%, one on standby, and one under maintenance.) An 18 month delay to the project would result from a change in the SO_2 scrubber design at this time.

The memo then calculated how a 18 month delay would cost approximately 1 billion dollars, due to additional interest and replacement power costs. The capitol cost of the equipment is cited as 236 million for SCR and 108 million for a 95% SO_2 scrubber. Operating costs listed as "Capitalized Operating Cost" are given as 784 million for SCR and 165 million for a 95% SO_2 scrubber.

NOTE: The above are only brief summaries of the information IPP submitted. The staff has not reviewed this information for its accuracy, and at this time, neither agrees or disagrees with the content of the submittal.

DK/JW:wml
2956